BC hydro

Project Justification

Kelly Lake to Cheekye Substation Second 500 kV Transmission Line

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System Transmission Planning Department
System Planning Division
System Development Group

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EXECUTIVE SUMMARY

This report summarizes the results of technical and economic studies which justify building the proposed Kelly Lake to Cheekye second 500 kV transmission line project by the fall of 1996.

B.C. Hydro's mission is to support the development of British Columbia through the efficient supply of electricity. B.C. Hydro has a responsibility to provide reliable electric service to its customers.

The existing B.C. Hydro bulk transmission system and the proposed second Kelly Lake to Cheekye line are shown in Figure A. Most of B.C. Hydro's power demand or electric peak load is centred in the Lower Mainland and Vancouver Island regions. Most of the power supply to this load centre is served from the two major remote sources of generation: Peace River and Kemano surplus generation in the north and Columbia River generation in the east.

The capacity of a transmission network to transmit power over long distances is limited by the thermal capacity of the lines, by electro-mechanical stability and by the supply of reactive power for voltage stability. Transmission system capacity deficiencies lead to increased operating complexity, decreased efficiency and a degradation of reliability.

The Interior to Lower Mainland transmission system (Figure A) is presently comprised of essentially five 500 kV lines: Kelly Lake to Ingledow; Kelly Lake to Cheekye; Nicola to Ingledow; Nicola to Meridian; and the Kelly Lake to Nicola line which allows sharing of transmission capability between the two sides of the system. Of these, the four lines into the Lower Mainland have series capacitors providing 50% series compensation. The proposed 50% series compensated Kelly Lake to Cheekye line would be the first line into the Lower Mainland in 20 years.

Northern generation capacity will be increased by 520 MW when Alcan's Kemano Completion Project goes into service in late 1994 or early 1995. The eastern generation could increase by more than 1500 MW over the next twenty years or so with the proposed resource developments in the Lower Columbia. In addition, there are expected to be industrial co-generation plants and Independent Power Producers (IPPs) located north of Kelly Lake and east of Nicola that would add to those totals.

Recent load growth in the Lower Mainland and on Vancouver Island will be supported by the American Creek series capacitor station north of Hope, completed in 1990. Anticipated near-term load growth will be supported by a dynamic reactive power supply source: a 200 Mvar static var compensator (SVC) at Dunsmuir Substation on Vancouver Island near Qualicum. The SVC is scheduled for service in fall 1993. By about 1995, further system reinforcement will be required if the electrical power demand continues to increase as forecast. B.C. Hydro is considering several options to meet the 1995/96 winter peak load.

The power transfer capability of the system is determined by power system computer simulation studies. The adequacy of this transmission capability is

judged by its compliance with B.C. Hydro's single contingency planning criteria and the reliability criteria of the Western Systems Coordinating Council (WSCC). The WSCC criteria define the permissible degree of impact on neighbouring utility systems due to credible disturbances initiated within the system of a member utility such as B.C. Hydro.

The capability of B.C. Hydro's Interior to Lower Mainland transmission system is predominantly limited by voltage stability. If this system is not reinforced, an outage of one of the 500 kV lines under system heavy load or heavy transmission stressed conditions could cause a sudden collapse of voltages and a widespread blackout in the Lower Mainland, Vancouver Island and perhaps the Puget Sound region.

The voltage stability limitation is also affected by the generation pattern; the constraint is greater at high Peace or high Columbia generation. Therefore, voltage stability limits often restrict the flexibility of operation of the Peace and Columbia generating plants. Restrictions on generation dispatch have an adverse impact on the economic operation of the system.

The system is planned primarily to meet any single contingency outage. However, the security of supply to Vancouver Island and the Lower Mainland against credible second contingency line outages is also of growing concern. During prolonged outages of any one of the major Interior to Lower Mainland lines, a subsequent outage of a second line is possible. Normally such situations are handled by redispatch and relying on load shedding. However, if the subsequent outage occurs under stressed conditions, it could result in significant load shedding with an attendant risk of voltage instability. Line and equipment outages are also becoming more and more difficult to schedule for essential system maintenance. Therefore selection of the recommended plan has considered the relative second contingency capability of the alternatives especially if they have similar costs.

Three studies were performed to determine the transmission system capacity requirements and the cost effective system reinforcement alternatives.

The **first study** established that the capability of the existing system with the system additions underway would be adequate only through the 1994/95 winter peak load period. It also assessed the sensitivity to changes in local and remote generation.

The **second study** evaluated approximately 35 different system alternatives to the proposed Kelly Lake to Cheekye transmission project for application in the mid 1990s. These included new transmission line alternatives and non-transmission alternatives and a review of emerging technologies. The technical and economic viability of all alternatives was screened with respect to their relative technical merit, cost, installation lead time and use of available and proven technology.

Among the non-transmission alternatives assessed were:

* Adding static var compensators in the Lower Mainland for dynamic reactive

power support;

* Increasing the series compensation of the existing 500 kV lines in the Lower Mainland region;

* Sectionalizing of some of the existing Interior to Lower Mainland 500 kV lines with a 500 kV switching station at Ruby Creek; and

* Enhancement of the existing system's performance with automatic control technology.

The **third study** determined the effectiveness of the best individual alternatives as a part of a long term system development plan. The approach taken in this study was to consider two basic alternatives for system development:

Sequence 1: to assess the sequence of projects that includes transmission alternatives early; and,

Sequence 2: to assess the sequence of projects that postpones new transmission additions as long as possible by the addition of relatively lower capital cost non-transmission alternatives.

The results of the studies show that there is very little difference in the long-term costs of the two system development options. The savings in transmission losses offset the higher capital cost of the transmission alternatives. The technical advantages of using proven and readily available technology and of providing the greatest system development and operating flexibility clearly favour the "transmission first" approach. Additional transmission is shown to be ultimately the most efficient and economical solution to the system capacity and reliability problem.

The proposed Kelly Lake to Cheekye second 500 kV transmission project provides a most reliable and cost effective means of increasing the Interior to Lower Mainland transmission system capacity to meet load growth beyond 1996. The proposed line would:

* Significantly reduce transmission losses which would cover, over its 45 year operating lifetime, approximately 114%, 86% or 66% of its total capital and operating costs, based on discount rates of 6%, 8% and 10%, respectively;

* Provide flexibility in B.C. Hydro's plans to minimize the risk of inadequate reliable system capacity in the future to meet the high load forecast, changes in resource plans, unforeseen delays in local IPPs and other system additions;

* Provide higher second contingency transfer capability than non-transmission options and, hence, significantly reduce the requirement to cut off supply to customers in the event of multiple outages of lines or station equipment;

* Provide greater flexibility for maintenance of system lines and associated substation equipment (it is already becoming difficult to schedule outages for such necessary activities); and

* Provide significant transmission capacity at peak load periods in the initial years and at off-peak periods over its lifetime which would increase the benefits of electrical trade of power and energy with the U.S. Pacific Northwest and for power pool transactions by the Power Exchange Operation.

The benefit/cost ratio of Sequence 1 compared to Sequence 2 for first contingency reliability and savings in losses is 1.15 at an 8% discount rate. It does not account for the unquantifiable benefits of increased flexibility for system operation and planning; benefits of reduced risk of blackouts due to multiple contingencies; and increased electrical trade within British Columbia and with Alberta and the United States.

It is recommended that the line be constructed for service in 1996 to meet the increased domestic load and to maintain system reliability, efficiency and operating and planning flexibility.

1.0 INTRODUCTION

This report provides a summary of the technical and economic justification for the proposed second 500 kV transmission line between Kelly Lake and Cheekye substations (circuit 5L46).

1.1 PROBLEM STATEMENT

B.C. Hydro's mission is to support the development of British Columbia through the efficient supply of electricity. To fulfil this mission, one of B.C. Hydro's objectives is to provide superior customer service through reliable power supply to its customers. As electricity consumption grows in the Lower Mainland and Vancouver Island regions, it is imperative that the major transmission system bringing electricity to those regions be reinforced to maintain system reliability; that is, to maintain an assured supply of electricity.

Reliability is a measure of the continuity of electric supply over an extended period. B.C. Hydro and the other interconnected member utilities of the Western Systems Coordinating Council (WSCC) have developed planning and design criteria which help ensure that their transmission systems meet high standards of performance under a variety of contingencies such as loss of generation, transmission line outages and other major equipment failure. Required performance levels vary according to the severity of the system disturbance and the prevailing system conditions, but, in general, loss of load is allowed only in case of very abnormal events.

During times of peak electricity use, the Lower Mainland and Vancouver Island regions obtain about 70% of their power requirements over long distance, high voltage transmission lines from Peace River generation in the north and Columbia River generation in the southeast of the province. Higher power transfer requirements caused by growing peak demand place increasing stress on the 500 kV transmission lines which supply the Lower Mainland and Vancouver Island through Kelly Lake, Nicola and Cheekye substations.

The combination of heavy demand for electricity, limited local generation and long, heavily loaded transmission lines can lead to voltage instability. Voltage instability can occur after a transmission line failure of any of the 500 kV lines which comprise the Interior to Lower Mainland transmission system. A line outage would cause a net loss of reactive power support contributed by the system transmission lines. This is because the increased current in the remaining parallel lines would cause the line inductive losses to increase and further offset the capacitive line charging. This would result in a downward spiral in the system voltage. The voltage decrease would exacerbate the problem because the current in the remaining lines would increase as the voltage drops. This would cause increasing demand for reactive power and a further decrease in the system voltage. As well, reactive power supplied by auxiliary equipment such as capacitor banks also would be reduced by the decrease in system voltage. The system generators and synchronous condensers (and SVCs in the future) would try to supply the sudden need for reactive power but if the system does not have enough dynamic

reactive power reserves, it would be doomed to lower and lower voltages. If a major system component fails during peak demand, voltage can drop below acceptable levels causing a "brownout". In extreme cases, protective relaying will operate to disconnect lines, leading to a much more rapid voltage collapse which will "black out" customers. If the collapse is not arrested, the effects could extend over a wide region. A further description and examples of the voltage instability phenomenon are provided in Section 5.1.

B.C. Hydro must also comply with its own System Planning Criteria and WSCC reliability criteria as outlined in Section 5.1(b). These criteria set forth standards for planning and operating the interconnected system. This means that the B.C. Hydro transmission system must be designed to meet high standards of performance under a variety of contingencies such as loss of generation, transmission line outages and other major equipment failure.

The Interior to Lower Mainland transmission system supplies the major metropolitan loads of the province. As well, this system is connected to the major load centres in the Pacific Northwest of the United States. A blackout of this system would have major economic, social and political ramifications. Therefore, an underlying planning principle is that loss of load should be avoided unless the cost to maintain acceptable performance exceeds the expected cost of outages to the consumer. While it is impossible to know exactly when this balance is met, planners use rules and criteria based on experience. This practice has resulted in an extremely reliable system. Because of careful planning, consumers rarely feel the effects of transmission system disturbances.

By 1995, the Interior to Lower Mainland transmission system will not have enough capacity to reliably serve new load. That is, a single contingency line outage during peak loads and maximum generation at Peace or Columbia plants would result in an unacceptable risk of voltage collapse of the system resulting in blackout of the Lower Mainland, Vancouver Island and perhaps the Puget Sound regions.

A strong, interconnected transmission system maintains the flexibility needed to cope with uncertainties. As the future cannot be predicted with accuracy, a transmission system should be strong enough to deal satisfactorily with load forecast uncertainties, construction delays of both generating units and transmission facilities, unexpected generating capacity outages and other unforeseen situations. While the value of such flexibility is difficult to quantify, it is an essential part of the determination of transfer capacity goals. In this situation, experienced and professional judgement is a key factor in measuring the value of various system reinforcement alternatives.

1.2 STUDY METHOD

The capability of the system and its interconnections with other regions have been assessed based on short-term and long-term needs. A study was undertaken to identify all available alternatives that would reliably meet consumer electricity requirements over the next 20 years. Screening criteria were applied to each one, narrowing the alternatives to the most promising ones.

Those that survived the initial screening were studied and evaluated in more detail. These studies have been documented in the following B.C. Hydro reports prepared by the System Transmission Planning Department:

Capability of the Interior to Lower Mainland Transmission System, Report No. SP 9009, March 1991

Interior to Lower Mainland Transmission Reinforcement Options, Report No. SP 9010, March 1991

Alternative Interior to Lower Mainland Transmission Reinforcement Sequences, Report No. SP 9011, March 1991

1.3 REPORT ORGANIZATION

The nature of the transfer capability restrictions and the voltage instability threat facing the Lower Mainland and Vancouver Island transmission system has been outlined above in **Section 1** of this report.

Section 2 describes the existing major transmission system with particular attention to the Interior to Lower Mainland portion of that system.

Section 3 summarizes the expected load growth, the basic reason for the growing voltage stability problem.

Section 4 outlines the generation resource development plan used in this study.

Section 5 covers planning criteria, the technical, economic and strategic aspects of the voltage stability problem and the selection of reinforcement alternatives for the Interior to Lower Mainland transmission system.

Section 6 provides the technical results of the transmission system simulation studies which confirm the system's vulnerability to voltage instability and determine the relative merits of the alternatives taken one at a time and in different combinations or sequences.

Section 7 includes a physical description and cost summary of the second Kelly Lake to Cheekye 500 kV transmission line project.

Section 8 outlines the benefits and costs of the second Kelly Lake to Cheekye 500 kV transmission line.

Section 9 summarizes the recommendations for reinforcing the Interior to Lower Mainland transmission system over the next ten years.

2.0 THE EXISTING MAJOR TRANSMISSION SYSTEM

In British Columbia, the primary generation resources are in the north on the Peace River and in the southeast on the Columbia River system. Most electrical consumption is in the Lower Mainland and on Vancouver Island. Most of the major transmission lines are routed from the hydroelectric generating plants in the north and southeast to the southwest corner of the province where most of the electricity is consumed. Electricity is supplied to the Lower Mainland and Vancouver Island from the Peace River through Kelly Lake Substation and from the Columbia River system through Nicola Substation. Figure 2.1 shows B.C. Hydro's existing major transmission system and the imbalance between installed generation capacity and electrical demand in the different regions of the province.

The B.C. Hydro system is interconnected with the Bonneville Power Administration (BPA) system in the United States by two 500 kV transmission lines from Ingledow Substation in Surrey to BPA's Custer Substation south of Blaine, Washington, and by two 230 kV transmission lines in eastern B.C. These intertie lines provide emergency support from BPA during disturbances in the B.C. Hydro system. They are also used throughout the year to export firm power to Seattle City Light[1] and for other power exchanges with the U.S. During periods of low electrical demand, the intertie lines can be used to export up to 2300 MW of surplus non-firm power. This export power, as well as the power to serve the Lower Mainland and Vancouver Island, must flow through the Interior to Lower Mainland transmission system; as a consequence, that system is heavily loaded for a large percentage of the time.

The relevant portion of the system is shown in Figure 2.2. The Interior to Lower Mainland 500 kV transmission system consists of five 500 kV lines (5L41, 5L42, 5L81, 5L82, 5L87). Of these, four (5L41, 5L42, 5L81, 5L82) directly supply the Lower Mainland load centre through Kelly Lake, Nicola and Cheekye substations. The four lines are equipped with mid-line series capacitors. The Interior to Lower Mainland system is bounded:

* in the north by Kelly Lake Substation which integrates Peace River and Kemano generation;
* in the east by Nicola Substation which integrates South Interior (primarily Columbia River), West Kootenay Power and TransAlta generation;
* in the west by Cheekye Substation which supplies the bulk of the Vancouver Island load; and
* in the south by Meridian and Ingledow substations which supply the Lower Mainland load; there are also two 500 kV transmission lines which connect Ingledow Substation with Bonneville Power Administration in the United States.

[1] The contract with Seattle City Light (SCL) is for a guaranteed supply of electric power which ranges from 150 MW in the summer up to 300 MW in the winter (B.C. Hydro's peak period). This came about when SCL agreed not to raise their Ross Dam and flood part of the Skagit Valley in British Columbia.

In addition to the two 500 kV circuits from Cheekye to Dunsmuir, Vancouver Island load is also supplied by two 138 kV circuits and a high voltage direct current (HVDC) bi-polar tie from Arnott Substation in Delta to Vancouver Island Terminal near Duncan as well as by approximately 450 MW of hydroelectric generation on the Island.

A total of approximately 1500 MW of hydroelectric generation (including that on Vancouver Island) is located near the Lower Mainland load centre, not including the 900 MW Burrard Thermal Generating Station. The Burrard plant is assumed to have essentially zero dependable capacity during winter peak load periods because of an uncertain and expensive winter fuel supply. However, four of the six units have synchronous condenser capability and the remaining two units can be run at 40 MW minimum output for voltage support if fuel supplies are available.

3.0 ELECTRICITY DEMAND FORECAST

The most significant factor in determining when new generation and transmission facilities are needed is the forecast of future demand for electricity. The probable 20-year forecast of the peak electrical power demand of the total integrated B.C. Hydro system is shown in Figure 3.1. This forecast has been derived from B.C. Hydro's report of January 1990, Electric Load Forecast 1989/90 to 2009/10, and a fall 1990 update of the first five years' growth, up to and including the 1995/96 winter peak.

The forecast of electricity requirements is based on projections of economic growth in the province, demographic changes, future fuel prices, energy price changes and the expected results of B.C. Hydro's demand side management (DSM) programs including Power Smart and co-generation. It also includes the residual loads which resulted from the discontinued Electric Plus (E+) program.

The forecast of probable peak load shown in Figure 3.1 has been defined as the total generation requirement at winter peak load. This means that the given forecast includes B.C. Hydro's domestic customer load (net of DSM and E+) and transmission losses. A breakdown of the probable peak load forecast is provided in Table 3.1 which also includes the generation supply requirements for firm exports to Seattle City Light and West Kootenay Power. The probable forecast shows a 2.2% average growth in peak load per year for the next 20 years. The load forecast for the Vancouver Island region is shown in Table 3.2 and its accompanying graph. This forecast assumes natural gas to the Island in 1991.

The Lower Mainland and Vancouver Island regions had a total peak demand in the winter of 1989/90 of about 5500 MW (approximately 70% of the weather adjusted total system peak of 7863 MW). The total demand in the Lower Mainland and Vancouver Island regions is expected account for approximately 70% of the total system peak load over the next ten to twenty years and to reach 7000 MW by the year 2000.

The forecast consists of three separate economic projections: High, Low and Probable, illustrating the range of uncertainty in expected growth outcomes. There are several sources of uncertainty in the forecast of future electricity demand including weather, economic activity, prices for electricity and fossil fuels, changes in technology and a continually changing mix of end uses. Of these, weather and overall economic growth are the principal sources of uncertainty (annual peak load can be about 5% higher than that forecast, with a probability of one year in ten years, due to abnormally cold winter conditions).

In December 1990, when British Columbia experienced extremely cold temperatures, the total system peak load reached 8122 MW (hourly average peak; the minute peak was 8200 MW) which approximately equals the 1991/92 winter forecast level of 8116 MW. The peak load on Vancouver Island at that time reached 2077 MW, about equal to the 1993/94 winter forecast of 2070 MW.

Uncertainty in future demand growth influences the planning process. The flexibility to meet different possible future demands is an important factor in judging alternative system development plans.

4.0 THE RESOURCE PLAN

As the consumption of electricity grows, resources must be developed to supply the required additional electricity. Each year a resource plan is proposed based on the latest forecast of future electricity demand.

Following are brief summaries of the new generation and other resources now scheduled or considered possible for the next 20 or more years to provide electricity for use by B.C. Hydro's customers. This schedule provides sufficient resources to meet the Probable forecast shown in Figure 3.1 and has the capability of advancing or delaying some developments if actual growth is above or below the Probable. The following projects and their schedules will be directly affected by the on-going success of B.C. Hydro's "3-Cs" initiatives: Conservation by all customers; Co-generation by industry; and Coordination with other utilities.

Power Smart Programs - These are on-going, customer-oriented, energy conservation programs which reduce future demand by encouraging more efficient use of energy. They benefit both the customer (through lower electricity bills) and B.C. Hydro (by postponing the need for new facilities, thus lowering financial commitments and delaying environmental impacts).

Resource Smart Programs - These are on-going programs intended to make existing generation and transmission facilities more efficient and thereby obtain significant additional energy from the B.C. Hydro system and allow development of new facilities to be postponed.

Coordination & Purchases

Inter-Utility System Coordination

B.C. Hydro has entered into a coordination agreement with the Bonneville Power Administration and is discussing the possibilities for coordination with Alberta utilities for mutual benefit and more efficient use of the interconnected power systems.

Alcan Purchase

B.C. Hydro has agreements in principle with Alcan for coordinated reservoir operation for fifty years and for the purchase of 2500 GW.h per year for twenty years, both beginning in early 1995 when Alcan's Kemano project, southeast of Kitimat, is scheduled for completion.

These coordination and purchase agreements offer B.C. Hydro an attractive combination of flexible supply and fairly-priced energy.

Independent Power Producers and Co-Generation - In the future, B.C. Hydro will be relying more on Independent Power Producers (IPPs) and increased co-generation by industry as a way of minimizing the cost of electrical service and postponing the development of large generation projects. Cost effective independent power production and co-generation can contribute a significant

portion of B.C. Hydro's supply requirements and allow deferral of more costly projects.

Downstream Benefits Arising from the Columbia River Treaty - The Canadian entitlement to downstream benefits (DSBs) resulting from the operation of water storage in the reservoirs at the existing Duncan, Keenleyside and Mica dams under the Columbia River Treaty was sold to the United States for a period of 30 years. Those downstream benefits will revert to British Columbia, starting in 1998/99.

Lower Columbia Development - Lower Columbia Development is a proposed series of seven resource developments in the Columbia River drainage primarily in the Trail/Castlegar area. The proposed projects would complete the development of generation potential of the Lower Columbia River and could potentially add a total of approximately 1550 MW.

Peace Site C - Site C, near Fort St. John, would be the third dam on the Peace River (W.A.C. Bennett and Peace Canyon dams near Hudson's Hope are already producing power). Should public demand for electricity continue to grow at the current forecast rate, power from Site C, which is planned as a 900 MW development, could be required by shortly after the turn of the century.

Other Hydroelectric Developments - The Lower Canyon site on the McGregor River and generation development on the Elaho River are both under study. They would have capacities of approximately 360 MW and 340 MW, respectively, with potential in-service dates within the first decade of the next century. The Homathko drainage near Tatla Lake is another possible hydroelectric generation development. A total of approximately 900 MW could be developed at three dam sites (Mosley, Waddington and Nude canyon) with potential in-service dates in the first or second decade of the next century.

Resource alternatives other than the development of large generating facilities are taking precedence in the preparation of the Resource Plan. Still, virtually all these resources are located quite far from where most of the electricity is consumed. The resource plan used in these studies is shown in Table 4.1. Over the next ten years, 2070 MW of new resources are planned. Of this total, 500 MW are planned for the Lower Mainland and Vancouver Island, 975 MW are planned for the Peace region and 595 MW are planned for the South Interior. Therefore, there is a continuing need to reinforce the major transmission system to reliably deliver electricity from the new resources to the growing customer requirements.

5.0 DEVELOPMENT OF THE TRANSMISSION SYSTEM INTO THE LOWER MAINLAND

5.1 TECHNICAL CONSIDERATIONS

(a) Power Transfer Capability

In order to maintain reliable performance of the power system serving the Lower Mainland and Vancouver Island regions, it is necessary to maintain adequate power transfer capability of the bulk transmission system into the Lower Mainland from the remote major generation resources. Step increases in the power transfer capacity of the system must be planned to meet increases in system peak load. The system must also meet future changes in generation dispatch and intertie transfer schedules as a result of generation resource additions in British Columbia and power exchange coordination agreements between B.C. Hydro and other major power producers such as Alcan, West Kootenay Power and utilities in Alberta and the western United States.

The power transfer capability of the transmission system is determined by technical studies which include computer simulations of system performance under steady-state and dynamic system disturbance conditions. System performance must comply with the minimum performance standards for disturbances of varying degrees of severity, as per B.C. Hydro's planning criteria and criteria established by the Western Systems Coordinating Council and the North West Power Pool (see below).

The technical impediments to increased power transfer capability of the bulk transmission system are presented by one or a combination of the following limitations:

* thermal capacity of the transmission line conductors and terminal equipment;
* electro-mechanical transient and dynamic stability;
* voltage stability.

Historically, when the transmission system was relatively lightly loaded, the dominant limitation in B.C. Hydro's bulk transmission system was transient stability. As line loadings have increased with time, the dominant limitation has become voltage stability for single line outages in the Interior to Lower Mainland transmission system south and west of Kelly Lake and Nicola substations.

(b) Reliability Criteria

Transmission planning criteria in use by B.C. Hydro for cost effective, reliable supply of power require that the system be designed and operated so that it is capable of withstanding the failure of any single major system element (e.g., a 500 kV circuit) during times of peak load or other high stress conditions. Following a single contingency system disturbance, no equipment should be operating beyond its emergency design limits. Consequently, the system is planned to have sufficient strength or capacity to maintain continuity and quality of service to electrical loads during the

most common or likely contingencies. For other less common contingencies (e.g., multiple line outages), it is not economical to provide enough capacity to maintain full service. Therefore, interruption of service or some reduction of quality of service is allowed for those conditions.

In addition, B.C. Hydro is a member of both the Western Systems Coordinating Council (WSCC) and the North West Power Pool (NWPP) and must comply with the reliability criteria of both organizations. Membership of the WSCC includes over 60 interconnected electric utilities in Alberta, British Columbia, 14 western states of the United States and the northern portion of Baja California, Mexico. It provides a forum for the coordination of planning, design and operation activities of its member utilities to promote reliability of power supply. The NWPP is a group of electric utilities in Alberta, British Columbia and the U.S. Pacific Northwest. The NWPP is mostly concerned with the operation of the systems of the member utilities and is a part of the WSCC as shown in Figure 5.1.

Utilities realize benefits from membership in both these organizations but also accept obligations to plan, design and operate their systems so that they will not create problems for their neighbours. Both organizations have defined criteria which they follow to help ensure adequate system performance following system disturbances of varying levels of severity and probability.

The WSCC criteria define acceptable levels of impact on neighbouring systems due to a disturbance initiated within the B.C. Hydro system. Under no circumstances should a credible contingency within the B.C. Hydro system result in uncontrolled shedding of firm load in neighbouring systems. In other words, these criteria restrict the degree to which B.C. Hydro can rely on its interties to the U.S.

(c) Voltage Stability

As mentioned above in Section 5.1(a), voltage stability has become the dominant limitation of the bulk transmission system serving the Lower Mainland and Vancouver Island regions.

The voltage and current at any point in the system define the amount of electricity flow at that point. The component of electric current in phase with the voltage defines the real power component, usually measured in megawatts. The component of current which is 90° out of phase with the voltage defines the reactive power component, usually measured in megavars. The reactive power can be thought of as the power required to sustain the electromagnetic fields necessary for sustaining the flow of real power.

In major load centres fed by long transmission lines, which is the case for the Lower Mainland and Vancouver Island, shunt capacitor banks are used to supply reactive power during periods of heavy load. The shunt capacitor banks are switched on when voltage sags as a result of reactive power consumption by the heavily loaded lines. Shunt capacitor banks are good, relatively inexpensive sources of reactive power and perform well if the voltage is fairly steady. However, as system voltage drops, their reactive power output goes down by the square of the voltage drop.

During heavy peak load, a major disturbance, such as loss of a critical line, causes a step increase in loading of the remaining parallel lines. This results in an increase in reactive power consumption and a drop in voltage levels. Generators in the load area automatically adjust reactive power output to restore balance but quickly reach their reactive capacity limits. Once this point is reached, there is no stabilizing force to counteract the destabilizing response of the shunt capacitor banks. The voltages decline progressively to either a sustained very low condition (brownout) or they rapidly collapse causing a total loss of load (blackout).

The phenomenon of voltage instability is just beginning to be well known and understood. A condition of voltage instability occurred in the North Coast region of the B.C. Hydro system in 1979, when voltages at some 500 kV buses (in the Skeena area) dropped by about 50% within one minute after a disturbance at Alcan's Kitimat smelter. A potential for such voltage collapse has been identified through system studies in the Puget Sound area. That area experienced extreme cold temperatures and record peak loads in January and February 1989. That imposed very heavy loadings on the portion of the Pacific Northwest transmission system which supplies the Puget Sound area from generation resources east of the Cascades. The utilities in the Pacific Northwest have developed operational procedures to deal with this problem in the short-term. They are now embarked on a major study of long-term solutions to the problem.

B.C. Hydro has been one of the leading utilities in the study of the voltage instability phenomenon. It has developed a set of criteria for ensuring adequate dynamic reactive (capacitive) var reserves for planning and operating the B.C. Hydro system.

(d) Security of Supply to Vancouver Island

The existing 500 kV line between Kelly Lake and Cheekye substations is one of the most heavily loaded lines in the system because much of Vancouver Island's electrical power supply flows over that line in addition to the electrical supply required in the Lower Mainland. A second Kelly Lake to Cheekye 500 kV line would provide greater security of power supply to Vancouver Island over the existing 500 kV major tie to Vancouver Island from Cheekye Substation to Dunsmuir Substation near Qualicum. The section between Malaspina and the Island consists of two 500 kV submarine cable circuits (1200 MW capacity each).

Security of supply to the Island is becoming critical. The two 138 kV alternating current (AC) submarine cable circuits (of 125 MW capacity each) between Arnott Substation in Delta and Vancouver Island Terminal near Duncan are now 35 years old and the high voltage direct current (800 MW HVDC system) submarine cable bi-pole tie between the same two substations are 18 to 20 years old. These cable intertie circuits are showing signs of deterioration and are approaching the end of their useful lives. The 138 kV cables have begun to fail due to corrosion and other aging problems and one of the cables (spare) is permanently out of service. Failure of any one of the remaining six single-phase 138 kV cables would result in permanent failure or forced

retirement of one 138 kV AC intertie circuit. One of the older HVDC cables has developed a small but stabilized oil leak and another is presently out of service for future repair of mechanical damage at one deep water location. Therefore, the Island will need to rely more and more on the 500 kV tie.

The vulnerability of electrical supply to Vancouver Island and the Lower Mainland was demonstrated on 11 November 1990, when heavy rain and flooding on the Green River caused the loss of two towers on the existing Kelly Lake to Cheekye 500 kV line (5L42) near Tisdall. The line was restored to service after 13 days by replacing the two failed towers by a single higher tower located further from Green River. Over that period, supply to more than 300,000 customers on Vancouver Island and the Sunshine Coast, along with some of British Columbia's largest pulp mills on the Island, at Howe Sound and at Powell River, relied heavily on the remaining 500 kV circuit into Cheekye from Meridian (circuit 5L45). Approximately two weeks after 5L42 was re-established, circuit 5L45 tripped and was out of service for approximately two hours because of equipment failure. In the last ten years there have been three instances of extended outages of the existing Kelly Lake to Cheekye 500 kV transmission line, 5L42.

An historical of the major outages of the Interior to Lower Mainland 500 kV lines is listed in Table 5.1. Experience shows that the system is vulnerable to weather related double line outages. Both western and eastern transmission corridors are subject to the same weather conditions; snow and ice storms usually hit both the Squamish and Hope areas. The proposed new line would provide support against such outages.

(e) Study Methodology

The various options for increasing the power transfer capability of the Interior to Lower Mainland transmission system, as described below in Section 6.0, were evaluated by a study of comparative increases in power transfer capacity. Since this capacity is essentially limited by voltage stability criteria, studies have been done to compare the increase in system dynamic reactive var reserves which result from various system reinforcement alternatives.

The critical system conditions studied when evaluating the voltage stability capability of the Interior to Lower Mainland transmission system can be divided into two groups:

* Peak load conditions during which the Peace and Alcan (Kemano) generating plants and any Independent Power Producers (IPPs) north of Kelly Lake Substation are operating at their maximum capacities; and

* Peak load conditions during which the Columbia generating plants and any IPPs east of Nicola Substation are operating at their maximum capacities.

With the Peace and Alcan generating plants operating at their maximum capacities, the western side of the major transmission system is heavily loaded. The most onerous single contingency under those conditions is an outage of one of the major transmission lines on the western side of the

system. The loss of the existing 500 kV transmission line between Kelly Lake and Cheekye substations (circuit 5L42) is usually the most critical outage under these conditions.

With the Columbia generating plants operating at their maximum capacities, the eastern side of the transmission system is heavily loaded. The most onerous single contingency under those conditions is an outage of one of the two 500 kV circuits from Nicola Substation to the Lower Mainland (5L81, Nicola to Ingledow, or 5L82, Nicola to Meridian). Since those two circuits are very nearly the same length and carry approximately the same load under normal conditions, the loss of one of them has approximately the same impact as the loss of the other.

(f) Study Assumptions

The major assumptions used for the system studies were as follows:

* Load growth as outlined in Section 3;
* Generation resources, including IPPs, as outlined in Section 4, Table 4.1;
* Dependable winter generation in the Lower Mainland and Vancouver Island assumed to be 1140 MW;
* Kemano Completion Project in-service with its full generation capacity of 1420 MW operational by 1995; maximum surplus Kemano generation export to B.C. Hydro during winter peak assumed to be 675 MW to 700 MW;
* Dunsmuir static var compensator installation considered operational in fall 1993;
* The third Williston to Kelly Lake 500 kV line commissioned by fall 1994;
* Intertie transfer to Bonneville Power Administration limited to firm export commitments to Seattle City Light (120 MW at winter peak);
* Intertie transfer to Alberta assumed to be zero; and
* Downstream benefits (DSBs), as defined in the Columbia River Treaty, assumed returned to B.C. Hydro starting with 100 MW in 1998, increasing to 600 MW in 1999 and to 1100 MW in 2003; 50% of DSBs assumed returned at Ingledow Substation in Surrey, 50% at Selkirk Substation near Trail.

5.2 ECONOMIC CONSIDERATIONS

(a) Methodology

B.C. Hydro's guidelines for economic comparisons of alternatives were applied in these studies. The Present Value method was used as the primary method for comparing the alternatives found to be technically feasible. The cost of each

alternative was determined including all capital costs, operating costs and savings in system losses.

For comparisons in which projects have different residual lives at the end of the study period, the residual life was accounted for by using the levelized annual cost method.

(b) Cost Factors

Discount rates are used to convert revenues and expenditures occurring in different periods to a common present value basis. The appropriate discount rate can vary depending on the analysis. B.C. Hydro, in consultation with the provincial government, has adopted an 8% net of inflation discount rate to evaluate its development options. This rate reflects the average pre-tax return to public and private investment in the economy. Sensitivity to a change in the discount rate was studied by also using net discount rates of 6% and 10%.

Corporate overhead costs for B.C. Hydro projects are estimated to be 8% of their direct capital cost.

Operating costs of new projects include operations and maintenance, administration and general expenses, insurance, grants and school taxes.

(c) Value of Electricity for Losses

The difference in system losses between the alternatives were evaluated on the basis of B.C. Hydro's marginal cost for electricity. That marginal cost represents the average cost of satisfying an additional domestic demand for electricity. The current marginal cost of electricity and its components, firm capacity and firm energy, are provided in Table 5.2 taken from B.C. Hydro's report The Cost of New Electricity Supply in British Columbia, December 1990. Sensitivity to a change in the long term value of electricity on the economic analysis was included in the study.

(d) Selection Criteria

Projects will generally be selected on the basis of the lowest long-term present worth cost. However, when present worth costs of alternatives are close, preference may be given to a higher present worth cost alternative on the basis of one or more of the following:

* lower initial capital cost;
* flexibility of the plan;
* technical preference;
* savings in losses; and
* other unquantifiable benefits and costs.

5.3 STRATEGIC CONSIDERATIONS

The overall objective of the transmission system development strategy is to shape tomorrow's system to assure customers of a reliable, efficient supply of electricity that minimizes effects on the environment and is socially acceptable.

(a) Improvements to the Existing System

The Interior to Lower Mainland transmission system is presently operating at capacity. The American Creek Series Capacitor Station, recently built north of Hope, increases the transmission capacity of the two existing 500 kV lines from Nicola Substation to Meridian and Ingledow substations in the Lower Mainland. B.C. Hydro is also vigorously following a program of adding shunt capacitors each year in the Lower Mainland and Vancouver Island system. This is being done in order to maximize the steady-state reactive power support for maintaining system voltages and to maintain the maximum dynamic reactive power reserves available at the local generators and synchronous condensers. There is also the upgrading of the existing 500 kV Peace transmission lines into the Lower Mainland which is now under way and should be completed by 1992. This will increase the amount of power that can be transmitted by the existing lines to help meet the increases in electricity consumption expected in the Lower Mainland and Vancouver Island regions.

(b) System Reinforcements

The Interior to Lower Mainland transmission system is essentially limited by voltage stability considerations. To avoid blackouts, the system is designed to maintain voltage levels within acceptable limits following disturbances. Planning strategies involve using a mix of reinforcement alternatives. Static var compensators, shunt capacitors, synchronous condensers and additional series capacitors installed at existing stations are relatively inexpensive and have short lead times, whereas new transmission lines are more expensive and require longer lead times. This mix of reinforcement alternatives can respond to changing load growth patterns, delays in major project approvals and other uncertainties.

For example, studies indicate that installation of a static var compensator (SVC) at Ingledow Substation or increased series compensation of existing lines, both of relatively low capital cost, may defer the need for the second Kelly Lake to Cheekye line by a few years. However, B.C. Hydro has as yet no operating experience with SVCs nor with high levels of series compensation and therefore cannot rely heavily on those alternatives. Strategically, it is better to advance the second 500 kV line between Kelly Lake and Cheekye to the earliest in-service date. That would minimize the risks of not having enough reliable system capacity in case load growth exceeds forecasts or in case unforeseen resource additions materialize north of Kelly Lake and east of Nicola substations, and/or in case of low water conditions at the hydroelectric generating plants in the Lower Mainland and on Vancouver Island.

6.0 TECHNICAL AND ECONOMIC ASSESSMENT OF SYSTEM REINFORCEMENT ALTERNATIVES

This section summarizes the results of the three supporting technical studies referenced in Section 1.2 (Reports No. SP 9009, SP 9010 and SP 9011).

The capability of the existing system, including projects now underway, was reviewed in the first study (SP 9009). That study established that the capability of the existing system with the system additions under way would be adequate only through the 1994/95 winter peak load period. It also assessed the sensitivity to changes in local and remote generation.

The second study (SP 9010), evaluated approximately 35 different system alternatives to the proposed Kelly Lake to Cheekye project for application in the mid 1990s. These included new transmission line alternatives and non-transmission alternatives and a review of emerging technologies. The technical and economic viability of all alternatives was screened with respect to their relative technical merit, cost, installation lead time and use of available and proven technology.

Alternatives considered include:

* Kelly Lake to Cheekye 500 kV transmission line;
* Other 500 kV transmission lines;
* Enhancements of the existing system;
* Non-transmission line options such as reactive power support substation equipment; and
* Emerging technologies.

The technical and economic feasibility of each alternative was assessed and those employing proven technology and with reasonable lead times were identified.

The third study (SP 9011) determined the effectiveness of the best individual alternatives as a part of a long term system development plan. The approach taken in this study was to consider two basic alternatives for system development:

i) To assess the sequence of projects that includes transmission alternatives early; and

ii) To assess the sequence of projects that postpones new transmission additions as long as possible by the addition of relatively lower capital cost, non-transmission alternatives.

In the first alternative sequence, the proposed Kelly Lake to Cheekye project and the proposed second 500 kV line from Nicola to Meridian were advanced to their earliest probable in-service dates. In the other alternative sequence, lower capital cost, non-transmission options and the second Nicola to Meridian line were advanced ahead of the Kelly Lake to Cheekye line. Comparing those two sequences shows that the former (Kelly Lake to Cheekye transmission first) would provide significant savings in transmission system losses compared to

the latter (non-transmission first). The effect of losses was one of the major factors included in the comparative evaluation of the two alternative sequences.

The intent of these three studies was to determine the cost effectiveness of the proposed Kelly Lake to Cheekye project relative to other feasible alternatives for both the near-term and the long-term future.

6.1 EXISTING SYSTEM CAPABILITY

The study entitled Capability of the Interior to Lower Mainland Transmission System, (B.C. Hydro Report No. SP 9009, March 1991), reviews the capability of the existing Interior to Lower Mainland transmission system with committed system additions through 1994. That study includes the effects of:

* American Creek Series Capacitor Station (completed in 1990), which provides 50% series compensation of the two 500 kV transmission lines between Nicola Substation near Merritt and Meridian and Ingledow substations in the Lower Mainland;

* The +200/-100 Mvar static var compensator at Dunsmuir Substation on Vancouver Island, scheduled for installation by fall 1993; and

* The proposed 120 MW of winter peak generation in the Lower Mainland and Vancouver Island regions expected from industrial co-generation.

The study defines the methodology and criteria used to assess voltage stability margins. It also assesses the sensitivity to changes in local and remote generation and to imports from BPA at Ingledow Substation, as shown in Figure 6.7. The effect of Burrard Thermal generation at different output levels is representative of changes in local generation. The effect of a fifth 460 MW generator at Revelstoke or a similar sized generator at Site C is representative of the effect of changes in remote generation in the South Interior or in the Central Interior, respectively.

The study confirms that some form of reinforcement of the Interior to Lower Mainland transmission system is required by fall 1995, when the peak load in the Lower Mainland and Vancouver Island regions is expected to exceed 6100 MW (corresponding to a total system peak of 8700 MW).

The variance in the dynamic reactive power reserve margin with variance in the combined Lower Mainland and Vancouver Island region load is shown in Figure 6.1(a). This indicates that the loadability of the Lower Mainland and Vancouver Island system corresponding to the planned 1994/95 system configuration is limited to about 6000 MW. Figure 6.1(b) shows that this limit is exceeded in 1993 based on the High load forecast; in 1995 based on the Probable load forecast; and in 2002 based on the Low load forecast.

6.2 TRANSMISSION SYSTEM REINFORCEMENT ALTERNATIVES

The study entitled Interior to Lower Mainland Transmission Reinforcement Options (B.C. Hydro Report No. SP 9010, March 1991) identifies several system reinforcement alternatives to the proposed second Kelly Lake to Cheekye 500 kV transmission line. Approximately 35 conceptual alternatives were initially identified.

Types of alternatives considered were:

* New transmission lines
* Upgrading existing lines (e.g., Bridge River transmission)
* Reactive support equipment (e.g., SVCs)
* Increased series compensation
* Line sectionalization (e.g., Ruby Creek switching station)
* Area Transmission reinforcement
* Generator voltage & var control schemes such as:
    * joint var control (JVC) schemes
    * line drop compensation (LDC)
* Single-pole reclosing line protection
* Remedial action schemes
* High Voltage Direct Current (HVDC) transmission
* 765 kV AC transmission
* Emerging technologies such as:
    * flexible AC transmission systems (FACTS)
    * high phase-order (HPO) lines.

The technical viability of each alternative was screened and ranked in terms of various factors:

* technical merit
* cost
* lead time
* commercially available technology
* commercially proven technology.

Based on this ranking procedure, the alternatives were classified into four broad classes, A to D, in order of descending overall technical merit (Class A alternatives have the highest technical merit). A list of all the alternatives considered and their classifications are shown in Table 6.1.

The Class A & B alternatives were subjected to more thorough technical and economic evaluations. The incremental power transfer capability provided by each alternative, on a 1994 system reference base, was determined for each of the alternatives as shown on Figures 6.2(a) and (b). It should be emphasized that this is a relative increase in first contingency transfer capabilities for the two generation conditions (maximum Peace or maximum Columbia generation). This corresponds to the transmission capacity that is secure against the outage of any single line in the system.

The Class C & D alternatives were considered to be of a lower order of merit at this time in context of meeting the multiple objectives of technical

effectiveness, proven technology, system compatibility and costs. The Class C alternatives merit periodic review and some merit further investigation. In time, it is expected that some of the Class C alternatives may be reclassified as Class B or even Class A. The Class D alternatives were considered unsuitable as planning options. However, some of both the Class C & D alternatives will be pursued for future applications to relieve operating constraints.

The relative increases in second contingency transfer capabilities due to 5L46, the Ingledow SVC and 65% series compensation alternative (i.e., the capability with one line already out of service for maintenance or due to a forced outage) was calculated for a few select combinations as shown in Figure 6.2(c). The second contingency transfer capability of the system due to the addition of a transmission line is shown to be significantly greater than would be the case for a non-transmission system reinforcement alternative.

The costs and description of each of the selected candidate alternatives are shown in Table 6.2. The derived net unit cost (net of savings in losses) per MW of incremental transfer capability is as shown on Figures 6.3(a) and (b).

The generally assumed routing of the candidate transmission alternatives, the second Kelly Lake to Cheekye 500 kV line and the second Nicola to Meridian 500 kV line, is shown on Figures 6.4 and 6.5, respectively. The Ruby Creek switching station is shown on Figure 6.6.

The study recommends that the following alternatives be considered as parts of the various system reinforcement sequences:

* adding 500 kV Interior to Lower Mainland transmission lines;
* adding static var compensators at key Lower Mainland and Interior buses;
* increasing series compensation of existing Interior to Lower Mainland 500 kV lines; and
* adding a switching station in the eastern Fraser Valley (Ruby Creek) to sectionalize the Interior to Lower Mainland transmission system.

6.3 LOCAL GENERATION ALTERNATIVES

Any future local generation in the Lower Mainland and Vancouver Island regions would affect some of the need for increased transfer capability of the Interior to Lower Mainland transmission system. The amount of transmission transfer capacity relief provided would depend on such factors as:

* Size of the generation addition (MW) and associated reactive support (Mvar) offered to the system;
* Generation capacity factor;
* Firm winter peaking capacity; and
* Dispatchability by B.C. Hydro operators.

B.C. Hydro is encouraging local generation in the Lower Mainland and on Vancouver Island by industrial co-generation and independent power producers (IPPs). The forecast amount of generation from these sources has been accounted for in the Resource Plan (Section 4) and its effect has been modelled in the technical studies.

Another alternative for local generation would be to use the 900 MW Burrard Thermal plant. Several alternatives are being considered with regard to the future use of this plant. One that has been used often in recent years is to run two units (#5 and #6) as generators at their minimum acceptable loading (i.e., mechanical vibration limits) of 40 MW per unit. That provides 2x150 Mvar of dynamic var reserve in addition to the 4x150 Mvar of reserve obtained from the other four units which are normally operated in the synchronous condenser mode. Units #5 and #6 have not been provided with the facility to operate as synchronous condensers because they are required for stand-by emergency power. Conversion of units from synchronous condenser mode to the generating mode can take up to a week per unit.

The demand charge to firm up the natural gas fuel supply to run units #5 and #6 at minimum load on an assured long-term basis has been estimated at about $6.7 million per year. The SVC costs for equivalent dynamic Mvar reserves would be in the order of $4 million per year. However, running the Burrard units provides a ready, although expensive, alternative in case of system difficulties.

The effect of local generation and imports from BPA on the transfer capability of the Interior to Lower Mainland transmission system was studied and documented in Report No. SP 9009. The effect of changes in local generation was modelled by varying Burrard Thermal generation output. The resulting changes in the Interior to Lower Mainland transmission system transfer capability are shown in Figure 6.7.

6.4 ADMINISTRATIVE OR NON-STRUCTURAL ALTERNATIVES

Non-structural alternatives which can help defer system reinforcements include demand side management, load curtailment and relaxing system transmission planning criteria.

(a) Demand Side Management (DSM)

Demand side management includes conservation and load management. These types of actions may be designed to influence customer use of electricity in ways that reduce the peak load on the Interior to Lower Mainland transmission system. Types of DSM actions are illustrated in Figure 6.8.

> **Conservation** is defined as the more efficient use of electricity in any of the consuming sectors: residential, commercial and industrial. As illustrated in Figure 6.8, conservation typically reduces the level of electricity use at all hours of the day and, therefore, can help reduce transmission requirements. B.C. Hydro's Power Smart program is an example of a conservation initiative.

Load Management is the demand side option most frequently associated with peak load problems. It is an area with which utilities in the Pacific Northwest (PNW), including B.C. Hydro, have the least experience since the PNW generating system has been energy-constrained and not capacity-constrained. Load management emphasizes the management of electricity use during a day (i.e., rescheduling some uses for other than peak times). This is illustrated in Figure 6.8 as load shifting.

Load management does not typically reduce overall electricity use or energy requirements. As with conservation, load management can be applied to all types of consumers.

The forecast of reduced electrical demand due to DSM has been accounted for in the peak load forecast shown in Table 3.1 and its effect has been included in these technical studies.

(b) Load Curtailment

Load curtailment is different from conservation and load management in that it is a reduction in the amount of electricity consumed by an end user through limiting the electricity supply or simply foregoing its use. It is a reduction of demand during times of system stress that is limited to a short, non-recurring period during which a need to reduce demand temporarily has been identified.

There are basically three different curtailment options: voluntary, involuntary and contractual.

Voluntary curtailment includes curtailment which could be achieved in the residential, commercial and industrial sectors at the request of B.C. Hydro and government agencies.

Involuntary curtailment could be implemented through rolling blackouts by B.C. Hydro without any action by end-use consumers.

Contractual curtailment includes industrial curtailment contracts.

B.C. Hydro has used only voluntary curtailment in the past under system emergency conditions and even that has been considered only as a short-term method for dealing with a temporary operating problem. B.C. Hydro is exploring the possibility of load curtailment to meet the 1995/96 winter peak load.

(c) Relaxing system transmission planning criteria

This implies accepting a less reliable power supply system. Since B.C. Hydro is obligated to meet WSCC reliability criteria and is charged with maintaining the level of system reliability its customers now have and expect in the future, this is not considered to be a viable option.

6.5 ALTERNATIVE 20-YEAR SYSTEM DEVELOPMENT PLANS

Report No. SP 9011, Alternative Interior to Lower Mainland Transmission Reinforcement Sequences, March 1991, examines two alternative system development plans out to the horizon year of 2013.

Sequence 1: The 500 kV transmission lines, Kelly Lake to Cheekye and Nicola to Meridian, are advanced to their earliest expected in-service dates (1996 and 1999, respectively). Non-transmission alternatives are used in-between the installation of the two lines and on through to 2013.

Sequence 2: The 500 kV lines are deferred as long as technically feasible by advancing non-transmission alternatives.

The two sequences are shown in Figures 6.9 and 6.10. Both were developed to meet B.C. Hydro's single contingency planning criteria. The relative increase in dynamic var reserves (which corresponds to the power transfer capability increase) with each system addition over the 20-year time frame for each of the two sequences is shown in Figures 6.11 and 6.12. The corresponding step increases in system capacity are overlaid on the load forecast in Figures 6.13 and 6.14.

An economic comparison of the two sequences with respect to aggregate net present value is shown in Table 6.3. At both a 6% and an 8% discount rate, Sequence 1 is more economic but at 10%, Sequence 2 is more economic. The net present value evaluation of the system additions in the respective sequences includes associated annual charges for interest, depreciation, operation and maintenance and taxes. It also includes an evaluation of the relative savings in transmission losses which, as shown, can be considerable in the case of Sequence 1. The MW peak loss reduction from 1996 through 2013 is illustrated in Figure 6.15. The evaluation of present value has been carried out at 6%, 8% and 10% discount rates. The 8% rate is normally used to evaluate alternative projects in B.C. Hydro.

The following sensitivity studies were included in the economic analysis:

i) The sensitivity of the net present value of the two sequences to a change in the discount rate is shown in Figure 6.16. The lower the discount rate the greater the amount by which the net present value of Sequence 2 exceeds that of Sequence 1; both are equal at a 9% discount rate.

ii) The sensitivity to a change in the long-term value of electricity used for evaluating savings in transmission losses is shown in Figure 6.17; Sequence 2 becomes more economic than Sequence 1 only when the long-term value of electricity falls below 40 mills per kW.h.

iii) The sensitivity to a change in the loss factor associated with evaluating the savings in energy losses for the two sequences is shown in Figure 6.18.

iv) The sensitivity of the net present value of the two sequences to a change in the total direct cost of the Kelly Lake-Cheekye transmission project is shown in Figure 6.19. The analysis shows that Sequence 1 would become less economic than Sequence 2 if the project cost exceeds 118% of the estimated cost.

The above economic comparisons only include the effect on system losses and do not take into account the following factors:

* The surplus single contingency capability at high Peace generation in the initial years of Sequence 1, in excess of that in Sequence 2, can be used to serve additional domestic loads or the electricity trade market;

* The second contingency capability of the system described for Sequence 1 is much superior to that of Sequence 2;

* Sequence 1 provides much more flexibility for maintenance and repair outages of system transmission lines;

* Transmission lines are significantly more reliable than non-transmission alternatives such as SVCs or series capacitors; and

* Sequence 1 relies on the use of proven technology in the earlier years.

The analysis of long-term pay back of the project by loss savings over its 45 year lifetime is shown in Table 6.4. This present value analysis shows that about 66% to 114% of the cost of the project would be recovered by the savings in losses alone, depending on the discount rate.

7.0 PROJECT DESCRIPTION AND COSTS

7.1 PHYSICAL CHARACTERISTICS

The proposed transmission project would consist of a single circuit, 500 kV, steel tower transmission line between Kelly Lake and Cheekye substations and associated station additions. It could include removal of all or part of one of the existing 230 kV transmission lines between the Bridge River generation plant and Cheekye (circuit 2L1). The proposed and alternative routes are shown in Figure 7.1.

The new line would be approximately 200 km long, depending on the route selected. Equipment would be required in both Kelly Lake and Cheekye substations to terminate the new line and series capacitors would be inserted near the mid-point of the line, probably at the existing Creekside Capacitor Station northeast of Pemberton. There could also be requirements for changes to the 230 kV terminations at Bridge River, Rainbow Substation at Whistler and Cheekye Substation if all or part of 2L1 were removed.

For this project, two basic types of lattice steel tower structures might be used. New delta configuration structures are being considered for this project because they would provide some technical advantages over conventional flat configuration structures.

Conventional (flat) (Fig. 7.2) - This configuration has been used almost exclusively to date for 500 kV transmission line construction throughout British Columbia. It consists of single circuit lattice steel structures supporting the three electrical phases (conductors) in a horizontal (or flat) configuration. Both self-supporting and guyed structures would be used with the requirements of terrain, climate, span length and other local factors determining which would be appropriate at each location.

Delta (Fig. 7.2) - This configuration would be new to the B.C. Hydro system. It consists of single circuit lattice steel structures supporting the three electrical phases in a delta or equilateral triangle configuration. Again, both self-supporting and guyed structures would be used. Structures for the delta configuration would be taller and more expensive than for the flat configuration but would require less right-of-way width and less clearing and would reduce electromagnetic field levels, radio interference and audible noise levels at the edge of the right-of-way and beyond. The delta configuration would also offer increased surge impedance loading and power transfer capacity when compared to the flat configuration.

Tower and conductor optimization studies have been carried out by comparing net costs of the two basic tower configuration alternatives with different sizes of conductors and different number of conductors per phase bundle. Net costs included credit for savings in transmission losses, credit for relative increases in line charging vars that provide reactive power support and credit for relative increases in surge impedance loading of the circuit which is an inherent measure of the power transfer capacity of the circuit.

Based on these optimization studies, a 927 mcm ASCR four-conductor phase bundle and the delta configuration structures have been selected for the proposed new 500 kV circuit although the flat configuration structures could be used where local conditions favour them. The 927 mcm conductor is about 50% larger than the 624 mcm conductor of the existing 500 kV line between Kelly Lake and Cheekye.

7.2 COSTS

Based on the proposed route, delta type structures and 4x927 mcm ASCR conductor bundles for the proposed new 500 kV line for a fall 1996 in-service date, the estimated capital costs for this project are as follows:

	$ Millions in 1990 Dollars
	Estimated Direct Cost
New 500 kV Transmission Line	$117.5
Complete Removal of 2L1	7.5
Creekside Series Capacitors	8.6
Kelly Lake Substation Line Termination (includes one line shunt reactor)	11.6
Cheekye Substation Line Termination	2.1
Rainbow (Whistler) 230 kV Substation Re-terminations	1.5
Rainbow 230 kV Tap	0.1
Total Project Direct Capital Costs	$149.0
Total Project Capital Costs including Inflation, Corporate Overhead and Interest During Construction	$230.6

The estimated direct capital cost can vary between $142 and $160 million due to route variations.

8.0 PROJECT BENEFIT AND COST ANALYSIS

8.1 METHODOLOGY

This benefit-cost analysis is based on the mandate that any new load that appears on the system must be served reliably and economically. In other words, it is assumed that B.C. Hydro's customers are willing to pay to maintain the same degree of reliability that they now enjoy. It has been assumed that B.C. Hydro's Power Smart program will eliminate loads that are more economically served by other means and remaining load growth will be served by the installation of new plant and equipment. As well, this analysis assumes that the reliability of the system will be maintained as new loads are added which require system additions that meet System Transmission Planning Criteria.

The benefits and costs of the project are determined by comparing alternatives that serve the load and maintain a similar degree of reliability. Second order differences in reliability are discussed but are not valued in the analysis. The benefit-cost calculation for the proposed project compares the two long-term sequences described in Section 6.5. Sequence 1 has new transmission installed first while Sequence 2 has non-transmission alternatives installed first. The sequence analysis assesses whether the line can be delayed and the technical implications and economics of delay. The benefit/cost ratio of Sequence 1 is determined by dividing the present value of the loss savings of Sequence 1 less Sequence 2 by the present value of the aggregate annual cost of Sequence 1 less Sequence 2.

8.2 QUANTIFIED BENEFITS

The benefit/cost ratio of Sequence 1 compared to Sequence 2 for first contingency reliability and loss savings is 1.15 at an 8% discount rate.

(a) Increased First Contingency Power Transfer Capability

The line is proposed to serve increasing load in the Lower Mainland and Vancouver Island. A reasonable method of valuing the benefit of staging this line in 1996 instead of a later date is to compare Sequence 1 against Sequence 2.

(b) Savings in Capacity and Energy Line Losses

The savings in losses for the long-term sequences are shown in Table 6.3. The long term savings in losses due to the proposed line alone are shown in Table 6.4. It is estimated that 86% of the capital cost of 5L46 could be directly recovered in line losses at an 8% discount rate and 114% at a 6% discount rate. Clearly the line is "Resource Smart" and would help meet the Corporate objective of being an efficient supplier of electricity.

8.3 UNQUANTIFIED BENEFITS

(a) Increased Interruptible Exports, Coordination, Short Term Sales

A second Kelly Lake to Cheekye transmission 500 kV line could be used during off-peak hours for secondary energy exports to the United States, coordination exchanges and even short term firm exports if any surplus capacity is available in the initial years of service.

(b) Second Contingency Capacity and Security of Supply to Vancouver Island

In the last ten years there have been three instances of extended outages of more than a day's duration of the existing Kelly Lake to Cheekye 500 kV transmission line (circuit 5L42). The most recent occurrence of an extended outage of 5L42 began on 11 November 1990, when heavy rain and flooding caused the failure of two towers. It took 13 days to restore that circuit to service requiring crews to work 16 hour days, seven days a week under quite adverse conditions.

Security of the Vancouver Island system becomes vulnerable during such extended outages of 5L42, especially to a concurrent outage of the existing 500 kV transmission line between Meridian and Cheekye substations (circuit 5L45) as described in Section 5.1(d). Circuit 5L45 terminates at Cheekye Substation and from there delivers supply to the Sechelt Peninsula and Powell River and to Vancouver Island via the 500 kV submarine cables. An outage of 5L45 during an outage of 5L42 at high load levels could cause a cascading failure or blackout of the whole Vancouver Island system and the Sunshine Coast. The proposed project would provide a third supply to Cheekye Substation and improve reliability of supply to Vancouver Island.

(c) Utilization of the New Line

Of the four lines (5L41, 5L42, 5L81, 5L82) that directly supply the Lower Mainland load centre through Kelly Lake, Nicola and Cheekye substations, circuit 5L42 is heavily loaded since it also carries a large proportion of the power supply for the Sechelt and Powell River areas and for Vancouver Island. The proposed new line, 5L46, parallel to 5L42, would increase the number of 500 kV lines directly supplying the Lower Mainland from four to five and would provide a more equal sharing of power. In other words, the new line would be well utilized as it would carry a substantial amount of power: about 1000 MW during system peak load. The new line would be well utilized not only in the near-term but also in the long-term.

(d) Increased Flexibility of System Operation

The proposed new 500 kV transmission line between Kelly Lake and Cheekye substations would add considerable flexibility for system operation. This would be in terms of the ability to vary the Peace, Columbia and Coastal generation for optimum utilization of resources; the ability to take maximum advantage of opportunities for electricity trade with Alberta and the U.S.; and the ability to better schedule line outages for equipment maintenance. This increased flexibility benefit is difficult to measure. For instance, in

June 1990, when both 500 kV lines connecting Revelstoke Generation (1850 MW) on the Columbia River to the transmission system in the Southern Interior were out for several days due to massive mud slides, B.C. Hydro also had to curtail all generation at Mica Generation (1750 MW), upstream of Revelstoke. This meant that B.C. Hydro had to increase output at the Peace River generating plants to make up the deficit. If the transmission capacity on the west side of the Interior to Lower Mainland system had been inadequate, as it would be in future years with only the existing system, it would have meant costly purchase of power from Bonneville Power Administration (BPA) or other northwest U.S. utilities.

(e) Planning Flexibility

The 1996 in-service date is based on serving domestic load only. That date has been chosen to allow some flexibility to meet a higher than forecast load, unknown firm exports or changes in the Resource Plan. With the line planned to be in-service to meet the probable load, the capacity of the system could be quickly increased by advancing installation of the planned SVC at Ingledow Substation to an earlier in-service date. If the load growth is lower than forecast, then the in-service date of the line could be delayed a few years. The benefit of this flexibility has not been quantified in this analysis.

9.0 RECOMMENDATIONS

Based on the forecast of future electricity demand, the resource plan and transmission planning studies, the Interior to Lower Mainland transmission system will require reinforcement beginning in 1995. If power demand continues to grow and the system is not adequately reinforced, loss of a major transmission line during high load periods would result in the interruption of supply to customers and an increased risk of a widespread blackout or extremely low voltages in large areas of the Lower Mainland and Vancouver Island and perhaps in the Puget Sound area.

To ensure continued reliable electricity supply to the Lower Mainland and Vancouver Island and to maintain planning and operating flexibility for efficient operation of the B.C. Hydro system, the following system reinforcement and actions are recommended after the Dunsmuir static var compensator is installed in 1993:

* Construct a second 500 kV transmission line between Kelly Lake and Cheekye substations including a series capacitor bank near the mid-point of the line for the earliest achievable in-service date of fall 1996;

* Secure fuel supply for one time use of a single Burrard unit at minimum output (40 MW) over the 1995/96 winter peak load period;

* Continue technical investigations of load curtailment options.

The use of additional transmission is shown to be ultimately the most efficient and economical solution to the system capacity and reliability problem.

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Figure 7.1 - Proposed Transmission Route and ALternatives, Kelly Lake - Cheekye 500 kV Transmission Line (5L46)

Figure 7.2 - Kelly Lake - Cheekye, 500 kV Transmission Line Project, Structure Types

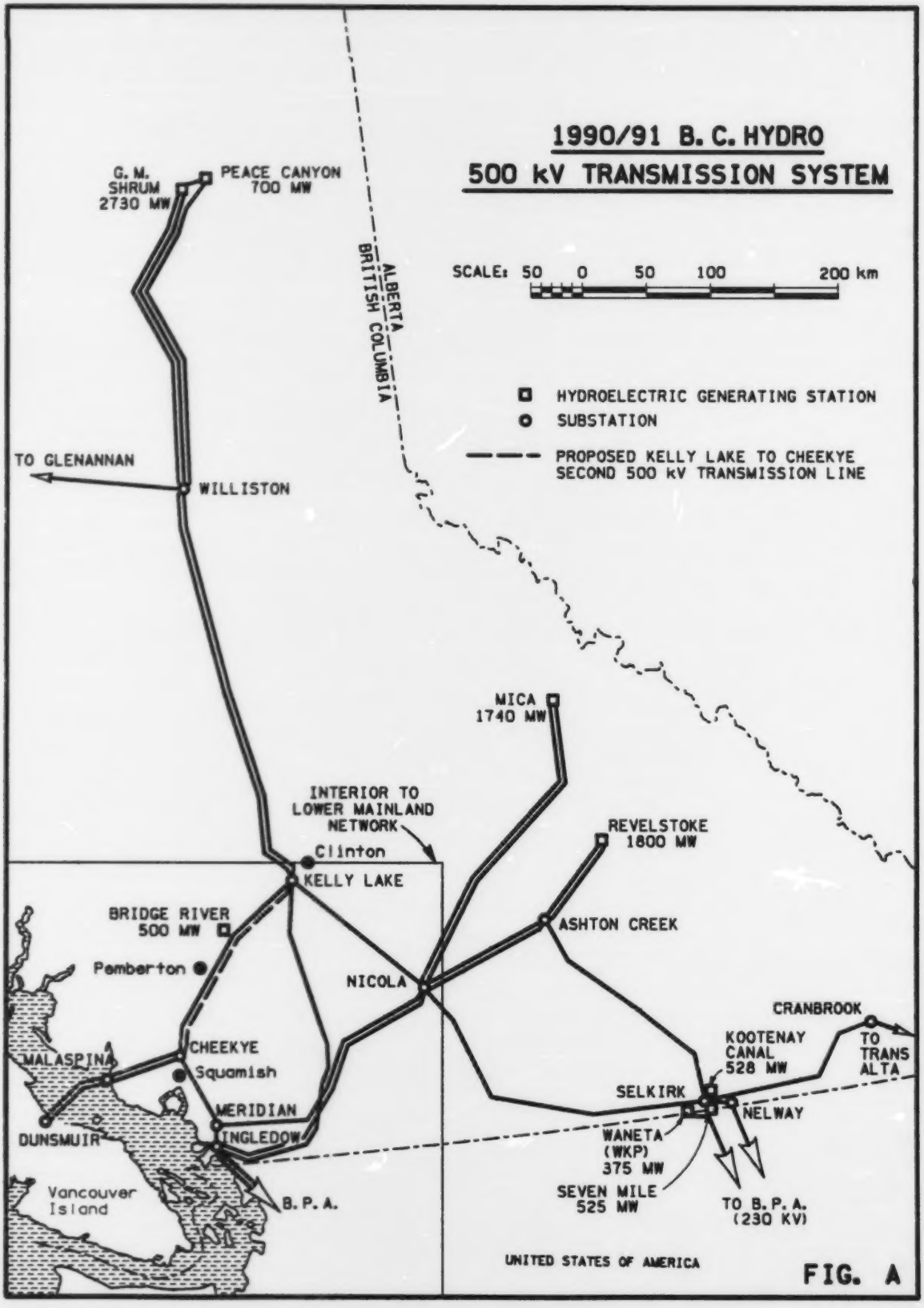

1990/91 B. C. HYDRO
500 kV TRANSMISSION SYSTEM
SCALE: 50 0 50 100 200 km
HYDROELECTRIC GENERATING STATION
SUBSTATION
PROPOSED KELLY LAKE TO CHEEKYE SECOND 500 kV TRANSMISSION LINE
ALBERTA
BRITISH COLUMBIA
G. M. SHRUM 2730 MW
PEACE CANYON 700 MW
TO GLENANNAN
WILLISTON
MICA 1740 MW
REVELSTOKE 1800 MW
INTERIOR TO LOWER MAINLAND NETWORK
Clinton
KELLY LAKE
BRIDGE RIVER 500 MW
Pemberton
ASHTON CREEK
NICOLA
CRANBROOK
KOOTENAY CANAL 528 MW
TO TRANS ALTA
MALASPINA
CHEEKYE
Squamish
SELKIRK
NELWAY
MERIDIAN
INGLEDOW
DUNSMUIR
WANETA (WKP) 375 MW
SEVEN MILE 525 MW
TO B. P. A. (230 KV)
Vancouver Island
B. P. A.
UNITED STATES OF AMERICA
441/JSMI.DGN

FIG. A

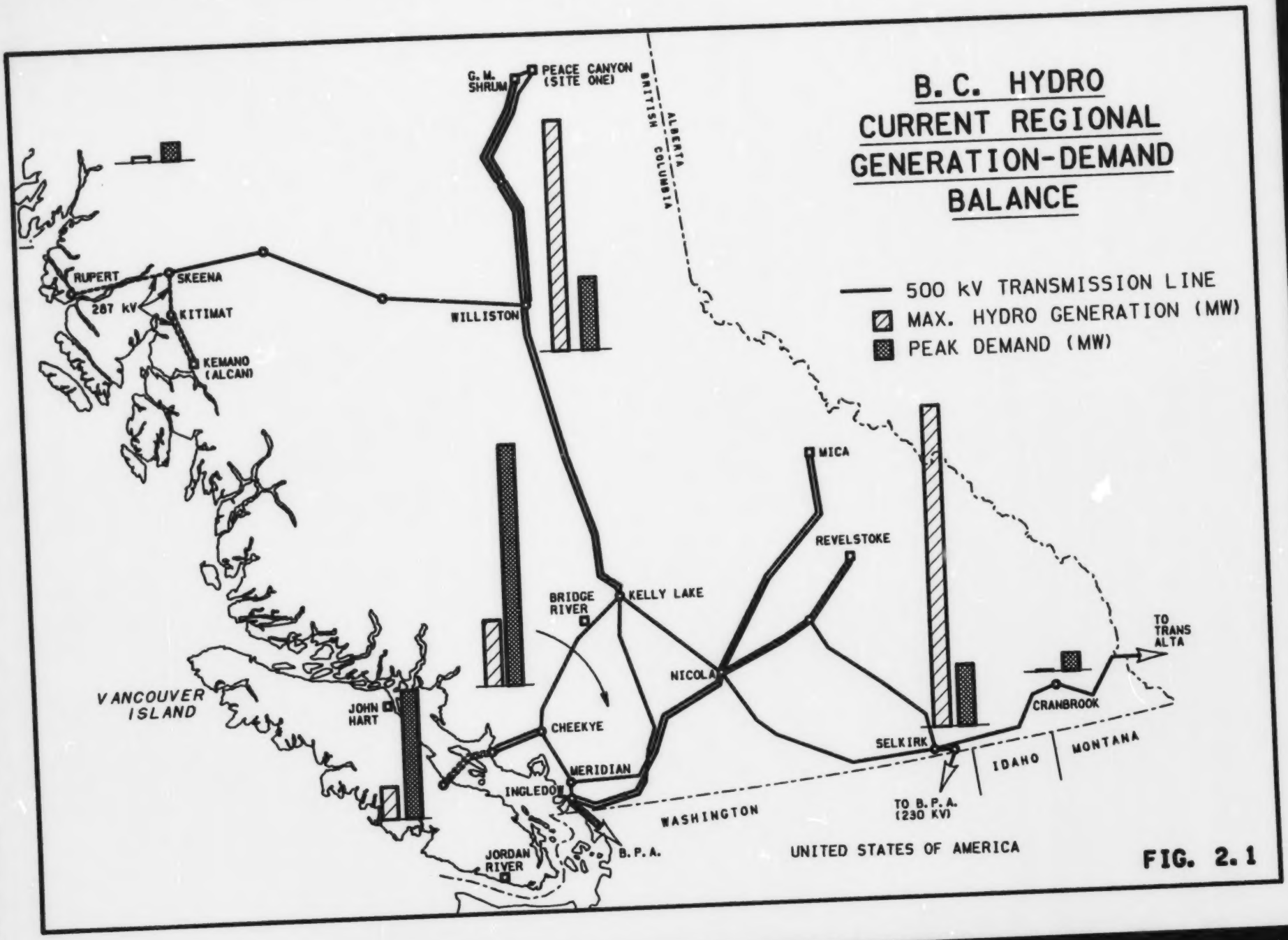

B. C. HYDRO
CURRENT REGIONAL
GENERATION-DEMAND
BALANCE
500 kV TRANSMISSION LINE
MAX. HYDRO GENERATION (MW)
PEAK DEMAND (MW)
G. M. SHRUM
PEACE CANYON (SITE ONE)
BRITISH COLUMBIA
ALBERTA
RUPERT
SKEENA
287 kV
KITIMAT
KEMANO (ALCAN)
WILLISTON
MICA
REVELSTOKE
BRIDGE RIVER
KELLY LAKE
NICOLA
TO TRANS ALTA
VANCOUVER ISLAND
JOHN HART
CHEEKYE
CRANBROOK
SELKIRK
IDAHO
MONTANA
MERIDIAN
INGLEDOW
WASHINGTON
TO B.P.A. (230 KV)
JORDAN RIVER
B.P.A.
UNITED STATES OF AMERICA

FIG. 2.1

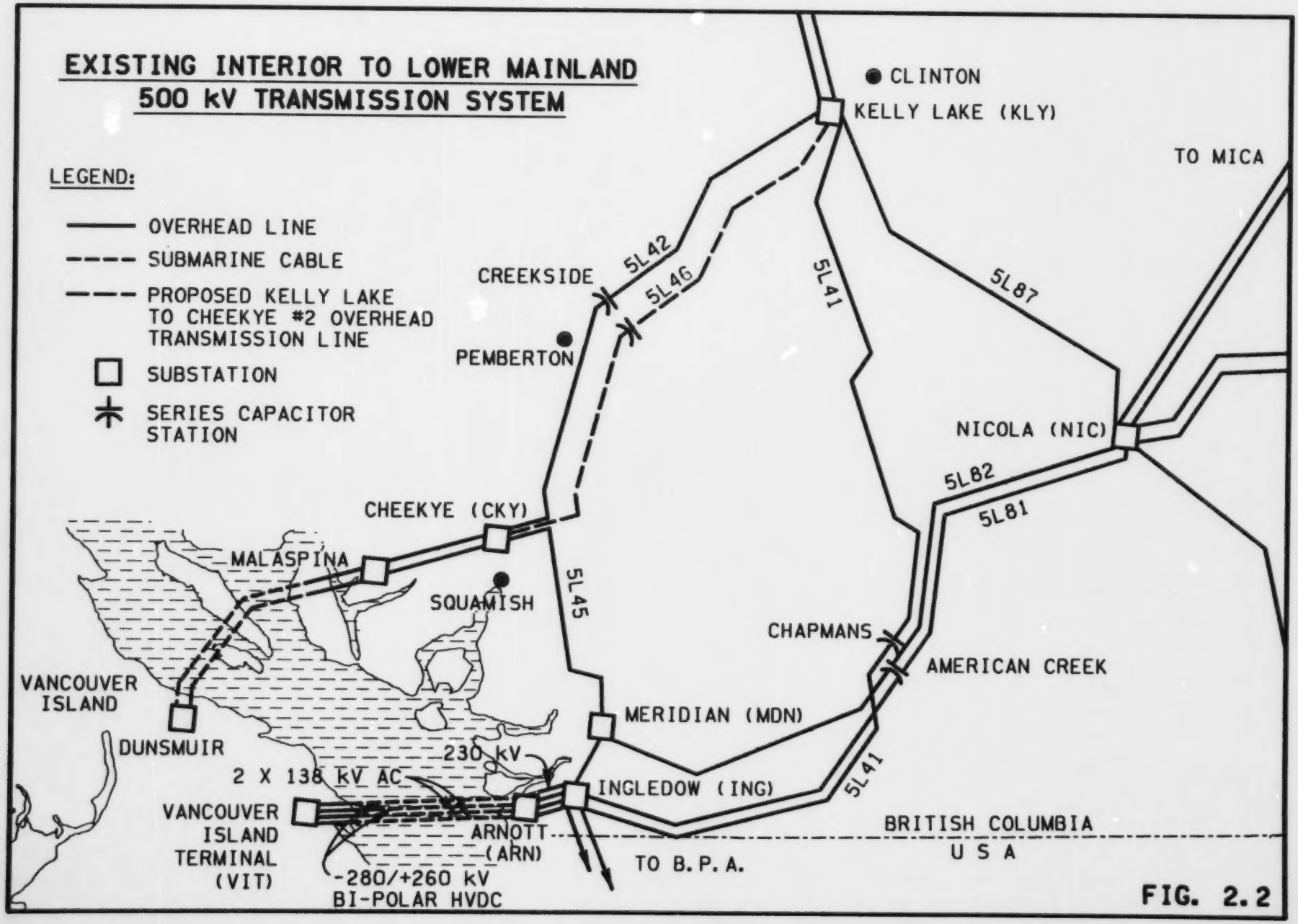
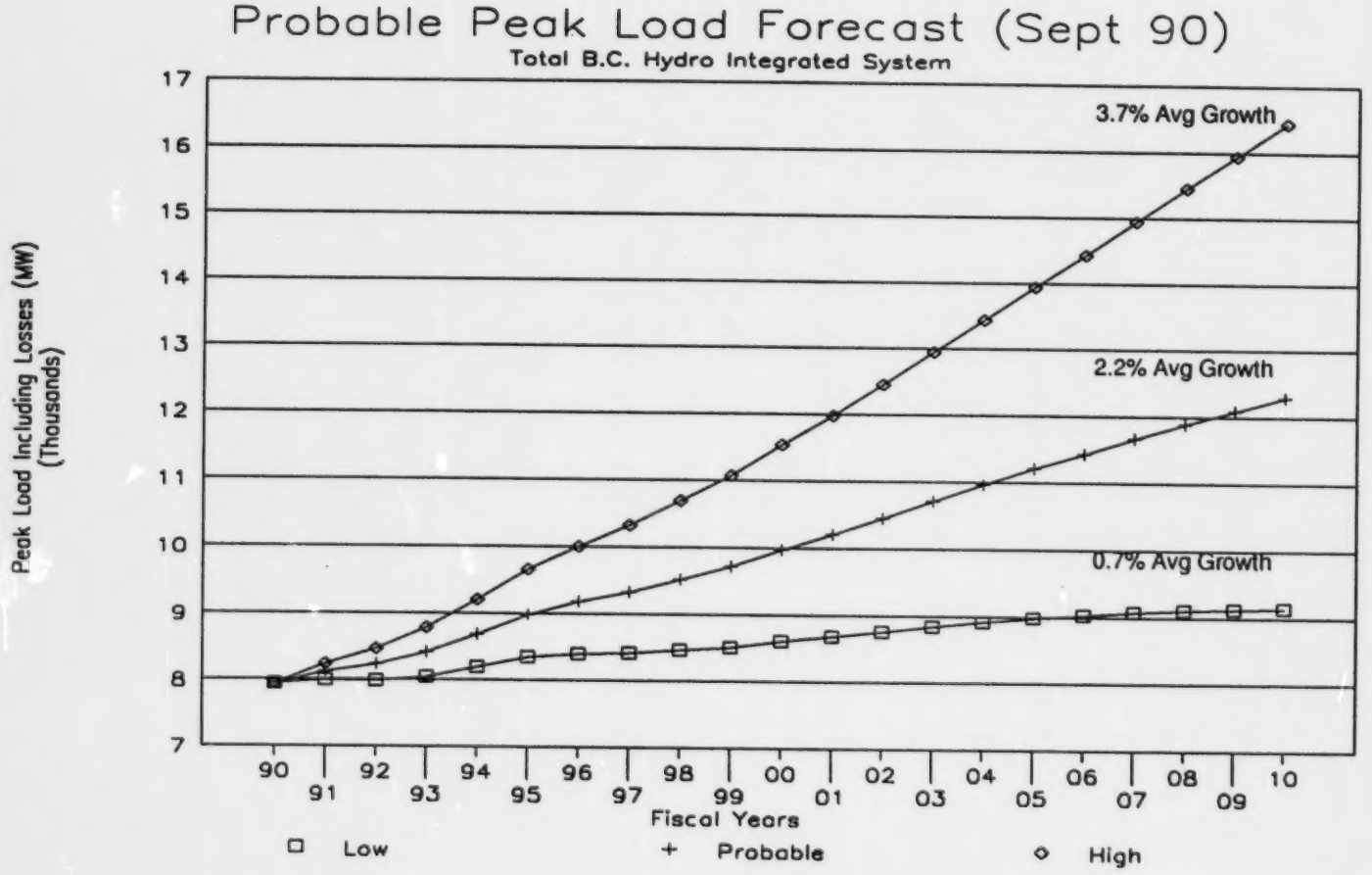

EXISTING INTERIOR TO LOWER MAINLAND
500 kV TRANSMISSION SYSTEM
LEGEND:
OVERHEAD LINE
SUBMARINE CABLE
PROPOSED KELLY LAKE TO CHEEKYE #2 OVERHEAD TRANSMISSION LINE
SUBSTATION
SERIES CAPACITOR STATION
CLINTON
KELLY LAKE (KLY)
TO MICA
CREEKSIDE
5L42
5L46
5L41
5L87
PEMBERTON
NICOLA (NIC)
5L82
5L81
CHEEKYE (CKY)
MALASPINA
SQUAMISH
5L45
CHAPMANS
AMERICAN CREEK
VANCOUVER ISLAND
MERIDIAN (MDN)
DUNSMUIR
230 kV
2 X 138 kV AC
INGLEDOW (ING)
5L41
VANCOUVER ISLAND TERMINAL (VIT)
ARNOTT (ARN)
BRITISH COLUMBIA
U S A
TO B. P. A.
-280/+260 kV BI-POLAR HVDC

FIG. 2.2



Note: Load levels shown include DSM & E+ programs and are based on the Sept 1990 Forecast.
High and Low assume growth rate is 1.5% higher or lower than Probable growth rate.

FIG. 3.1

WESTERN SYSTEMS
COORDINATING COUNCIL
GENERAL LOAD AREAS
I Northwest Power Pool Area
II Rocky Mountain Power Area
III Arizona–New Mexico Power Area
IV California–So. Nevada Power Area
0 100 200 300 MILES
SCALE
FORT ST. JOHN
HUDSON
ALICE ARM
DAWSON CREEK
KITIMAT
PRINCE GEORGE
ALBERTA
BRITISH COLUMBIA
EDMONTON
VANCOUVER
CALGARY
TRAIL
WASHINGTON
SEATTLE
OLYMPIA
SPOKANE
MONTANA
PORTLAND
SALEM
HELENA
BUTTE
NORTH DAKOTA
EUGENE
I
OREGON
BOISE
IDAHO
SOUTH DAKOTA
WYOMING
IV
NEVADA
RENO
CARSON CITY
CHEYENNE
SAN FRANCISCO
SACRAMENTO
SALT LAKE CITY
NEBRASKA
II
UTAH
COLORADO
DENVER
CALIFORNIA
LAS VEGAS
MONTROSE
COLORADO SPRINGS
KANSAS
LOS ANGELES
III
SANTA FE
OKLAHOMA
ARIZONA
ALBUQUERQUE
SAN DIEGO
PHOENIX
NEW MEXICO
TUCSON
EL PASO
TEXAS
MEXICO

FIG. 5.1

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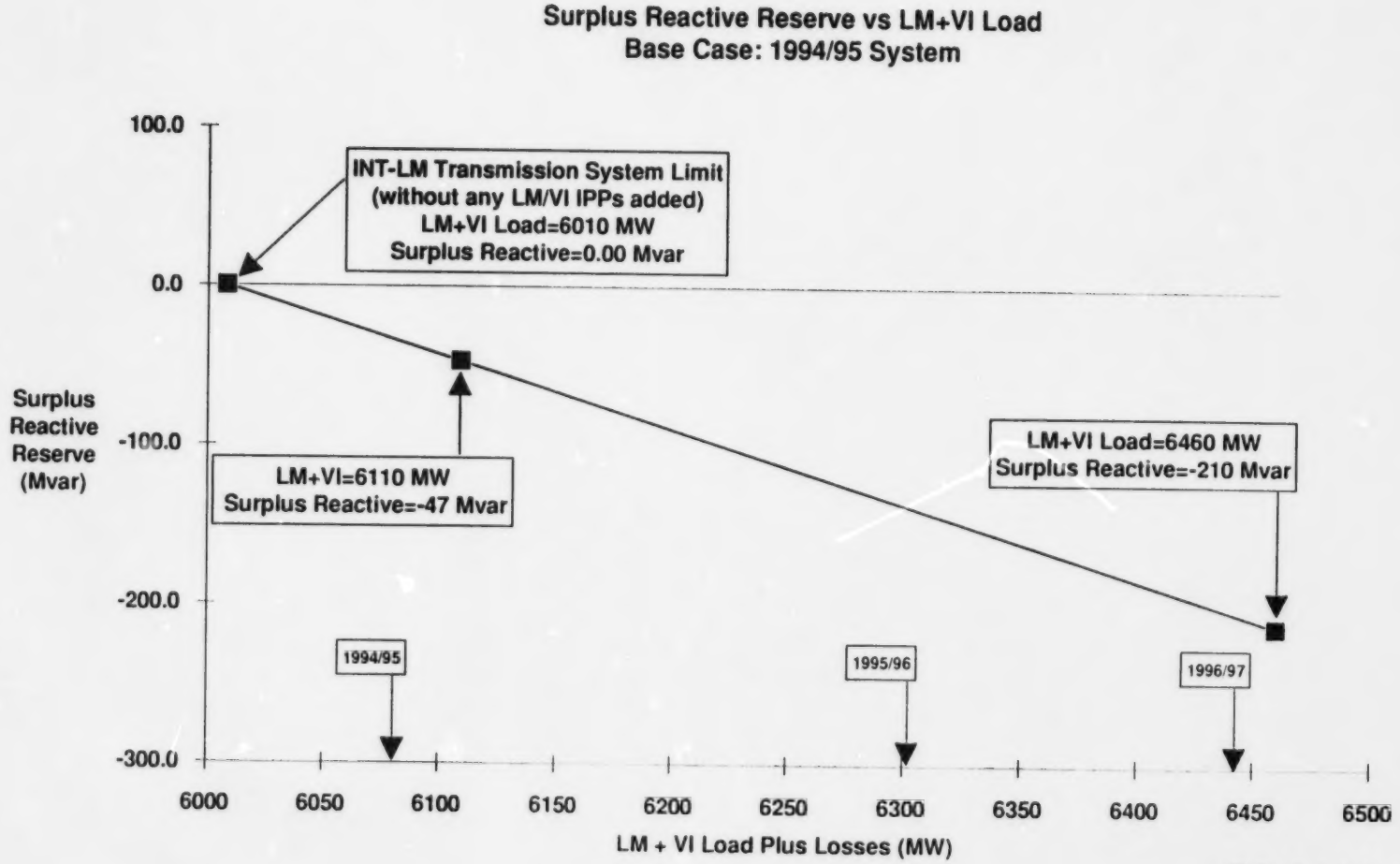

FIG. 6.1 (a)

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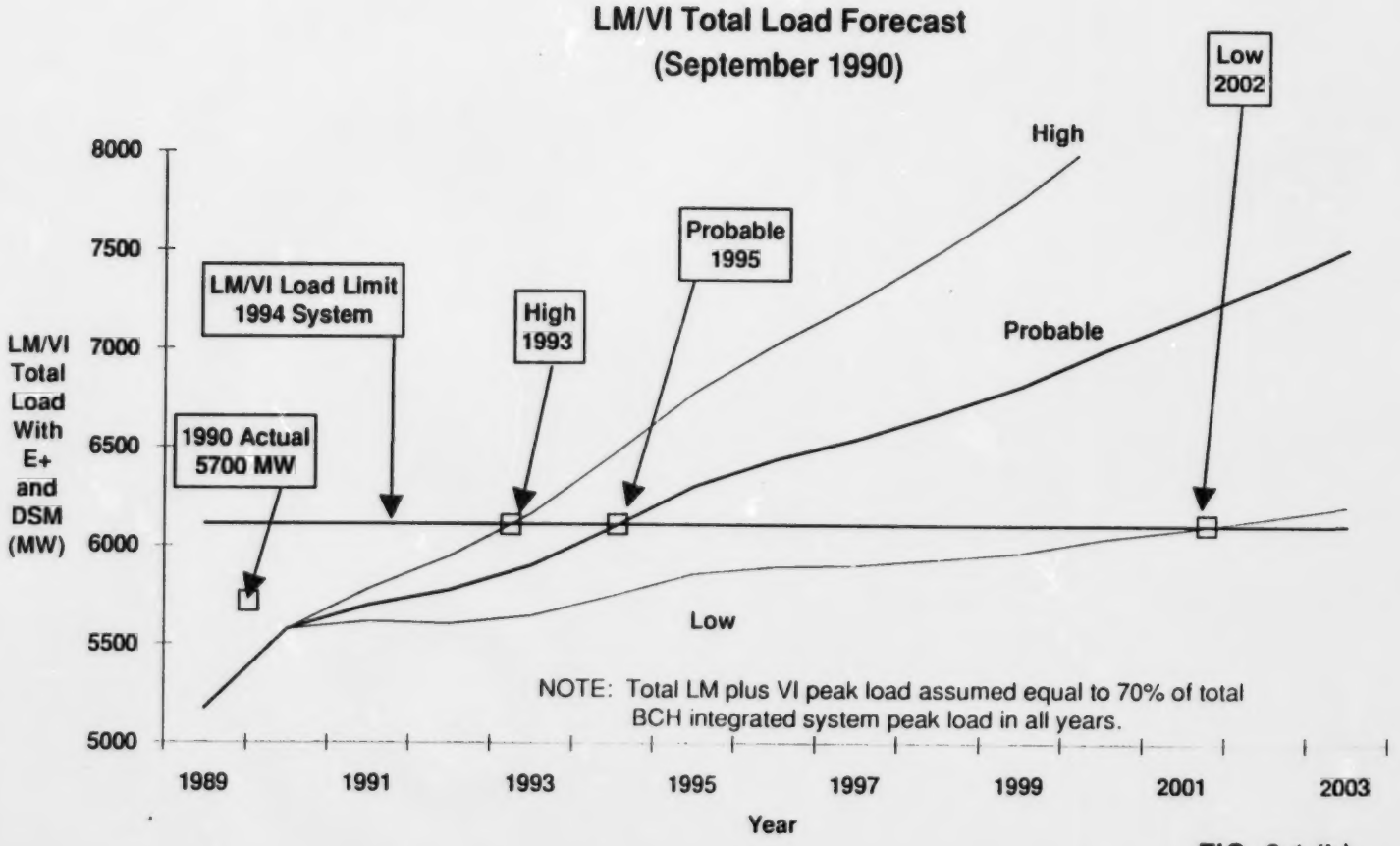
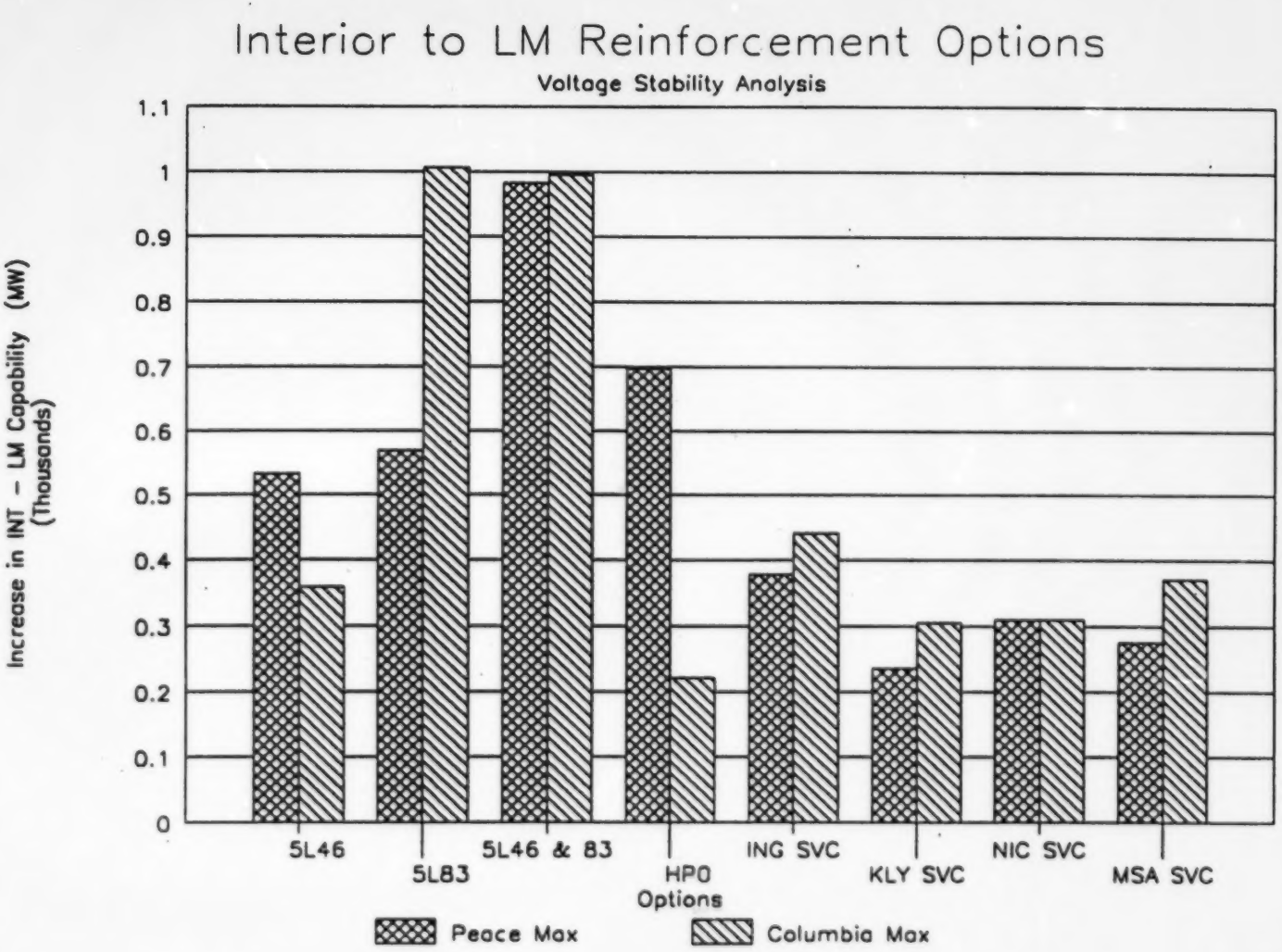
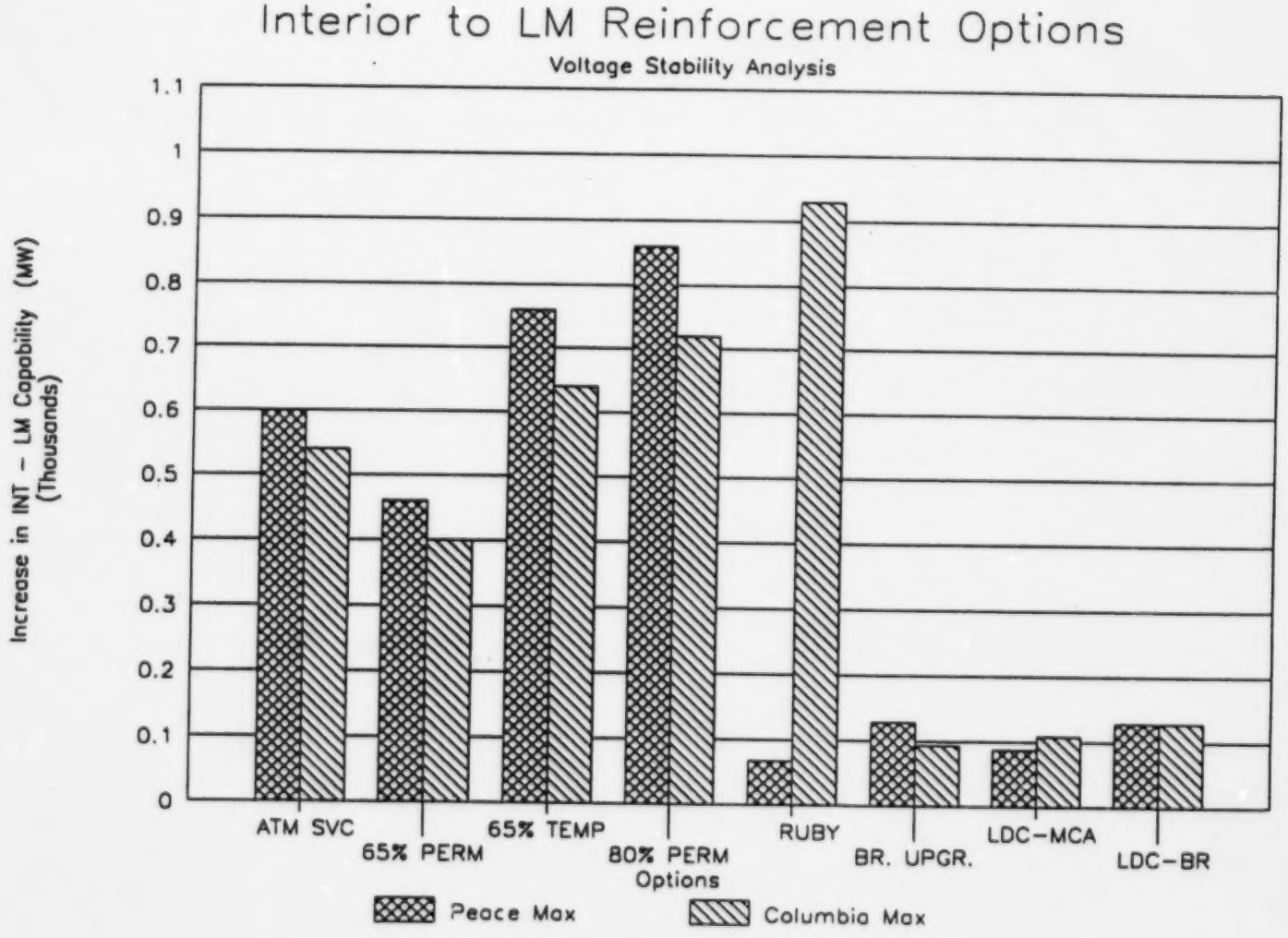


FIG. 6.1 (b)



Note: Refer to Table 6.2 for definition of each option.

FIG. 6.2 (a)

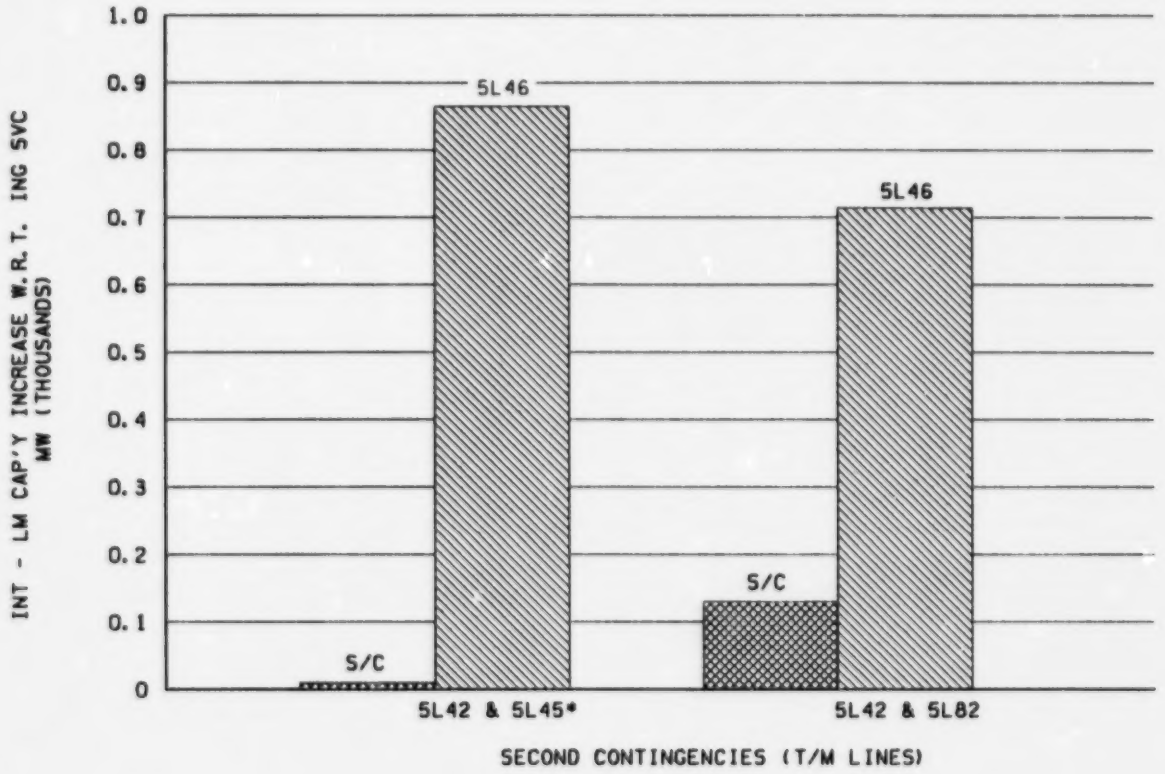


Note: Refer to Table 6.2 for definition of each option.

FIG. 6.2 (b)

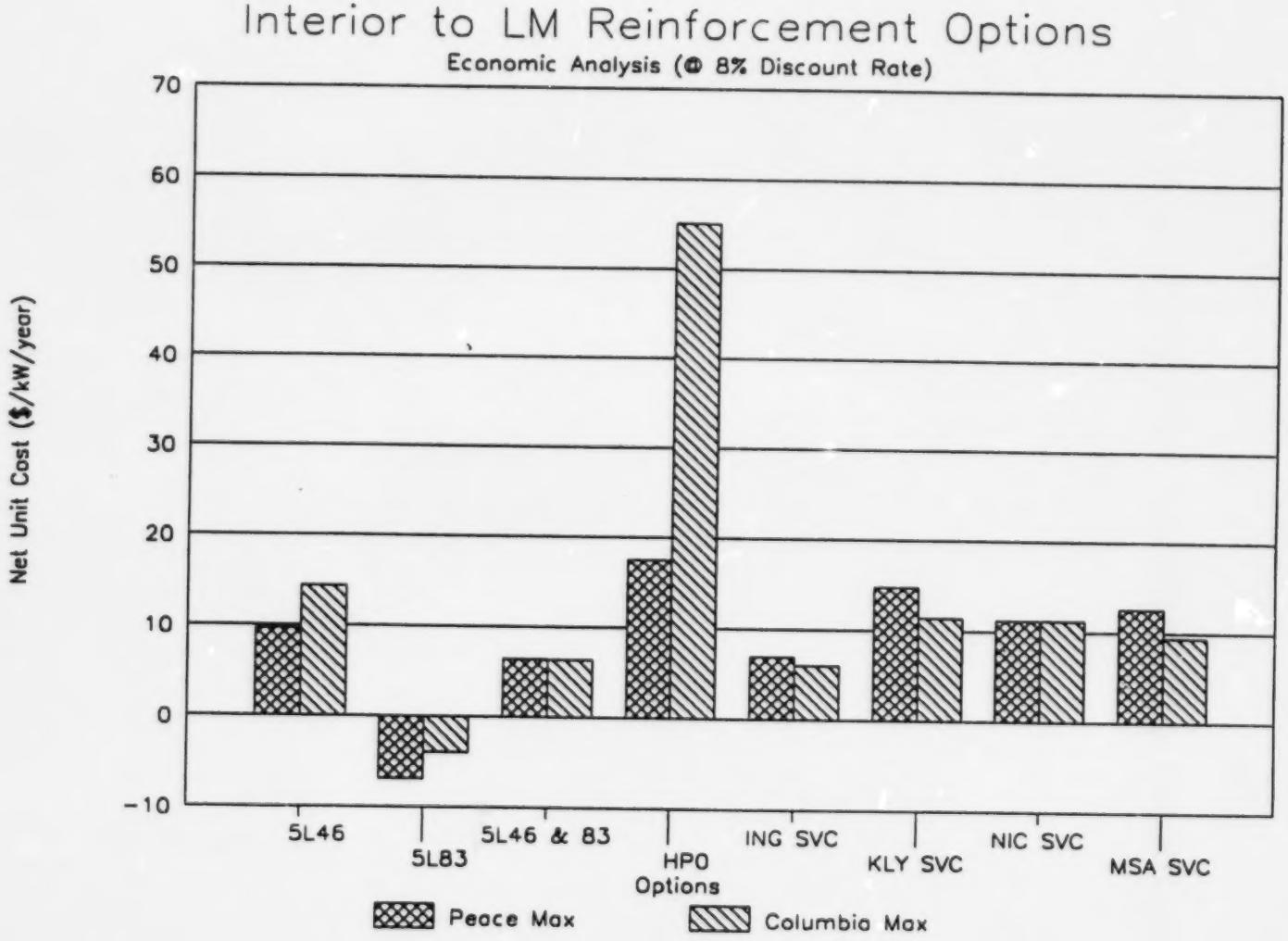
2ND CONTINGENCY INT - LM TRANSMISSION CAPABILITY COMPARISON (1995)

5L46 LINE OR 65% SERIES COMPENSATION (S/C) VERSUS INGLEDOW SVC OPTION



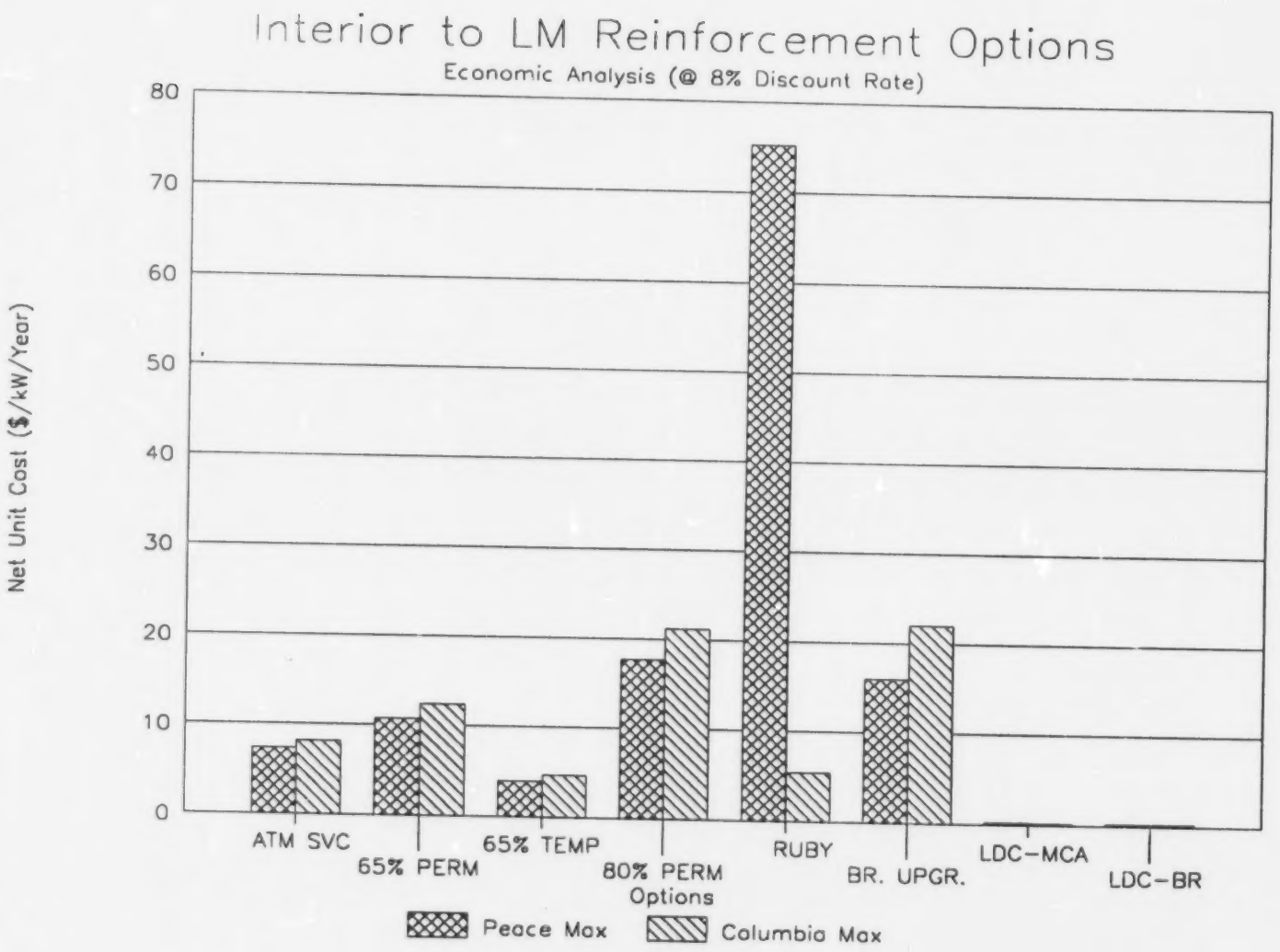
* FOR THE S/C AND SVC OPTIONS THIS EFFECTIVELY MEANS AN OUTAGE OF THE 500 KV TIE TO VANCOUVER ISLAND AND SECHELT PENNINSULA AND A LOAD REDUCTION IN THIS REGION UP TO THE MAXIMUM DEPENDABLE CAPACITY OF THE LOCAL GENERATION AND THE REMAINING PARALLEL TIES.

FIG. 6.2(c)



Note: Refer to Table 6.2 for definition of each option.

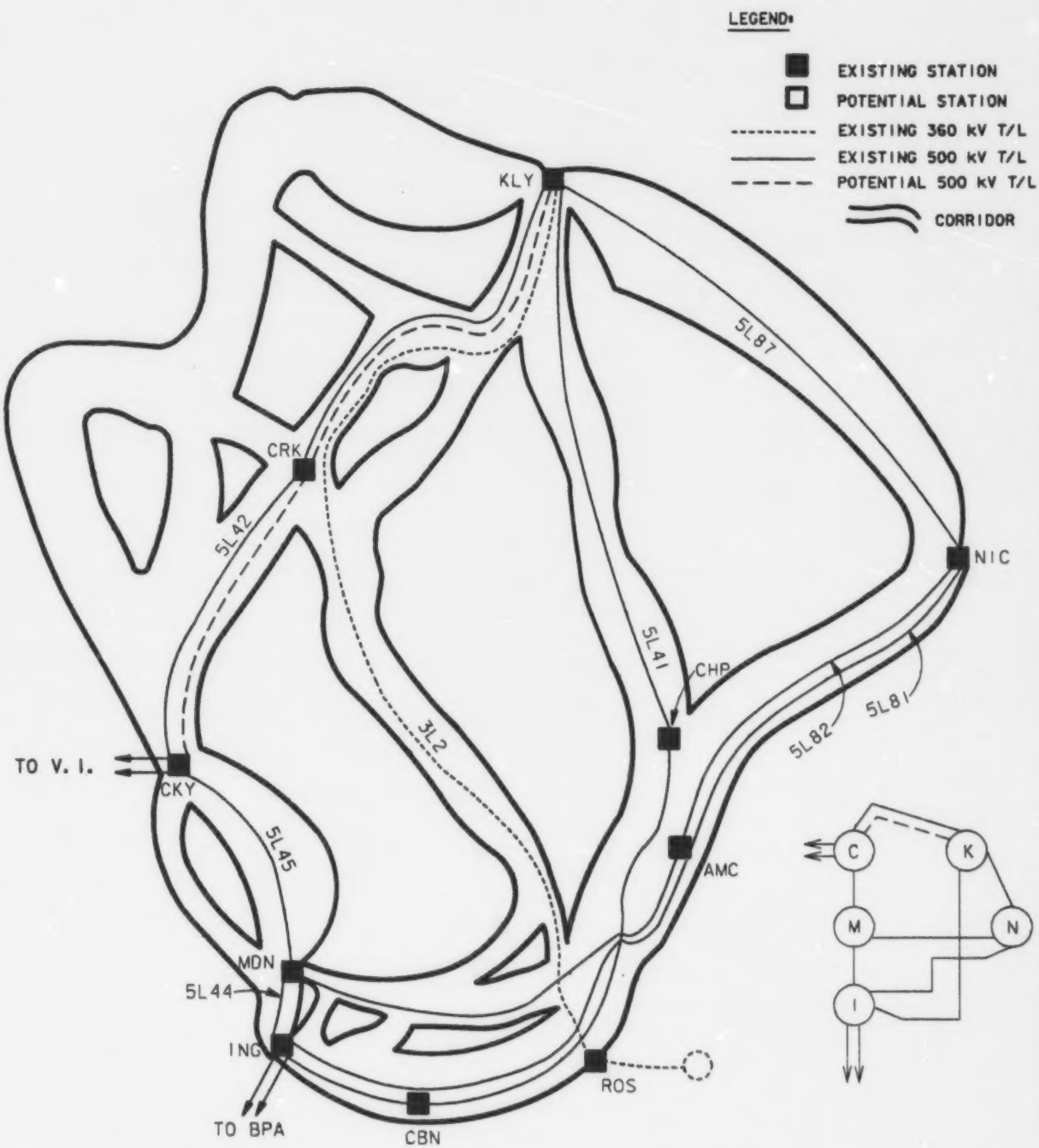
FIG. 6.3 (a)



Note: Refer to Table 6.2 for definition of each option.

FIG. 6.3 (b)

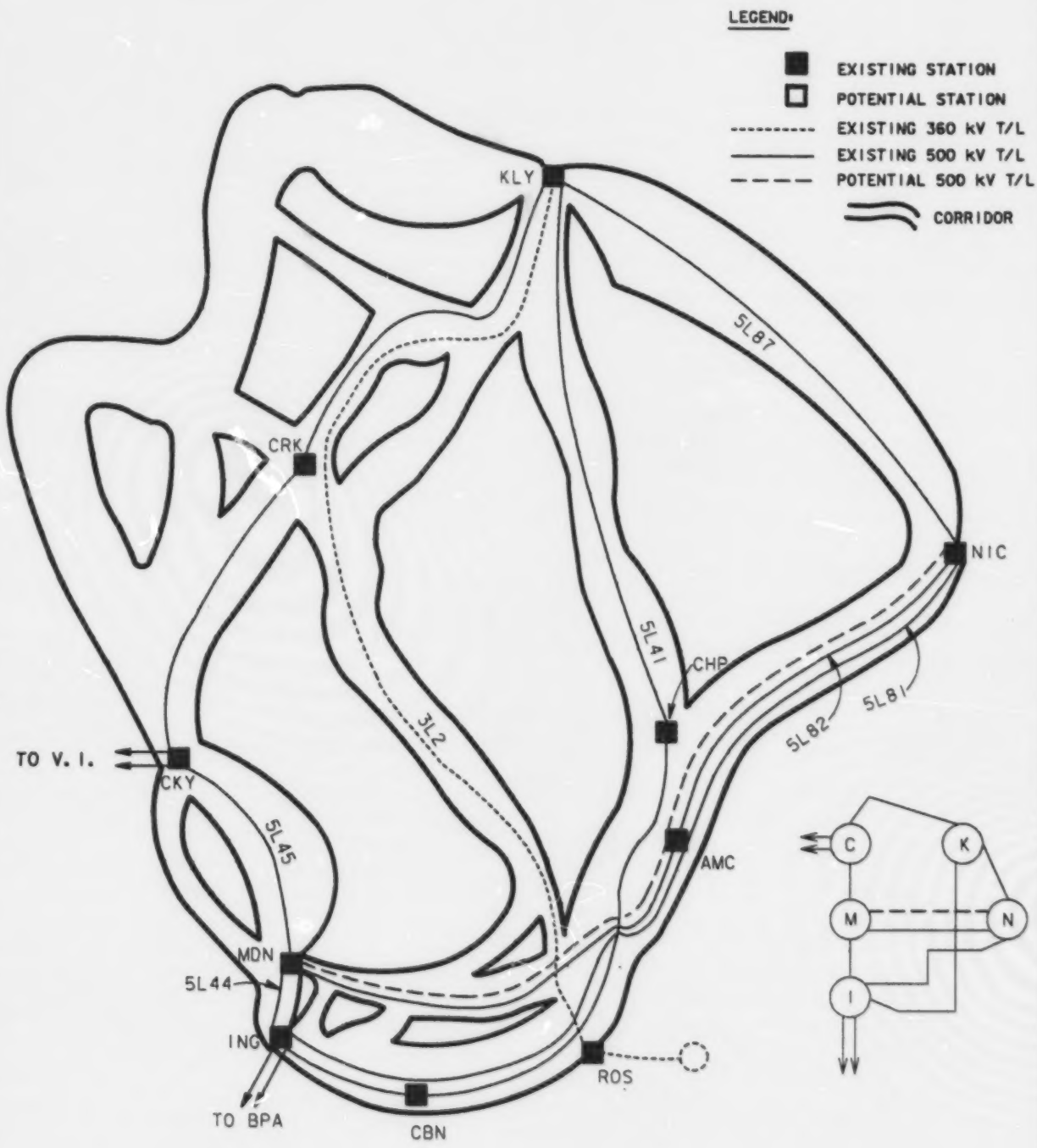
INTERIOR-LOWER MAINLAND
TRANSMISSION PLAN



KELLY LAKE - CHEEKYE
#2 500 kV TRANSMISSION LINE

FIG. 6.4

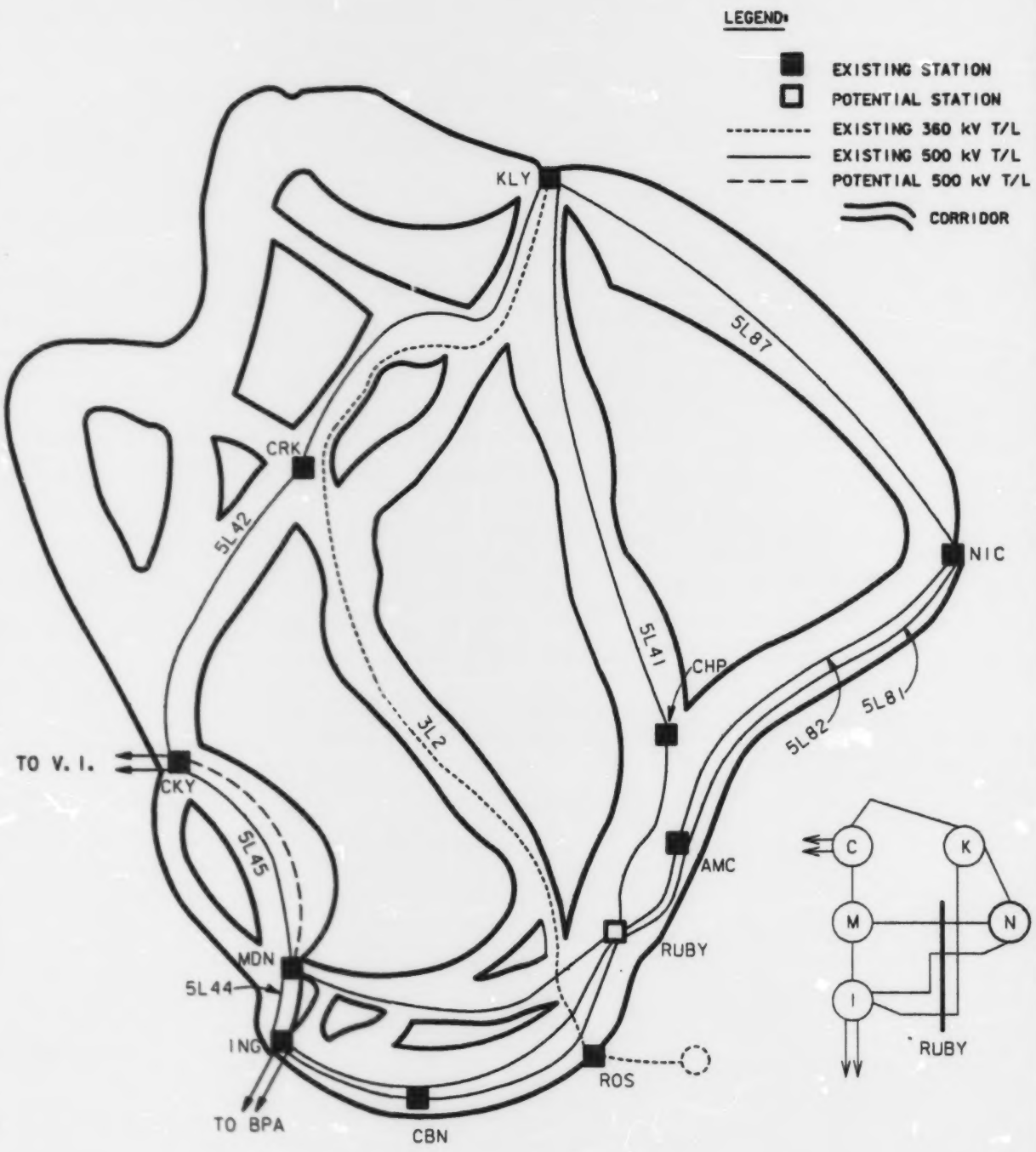
INTERIOR-LOWER MAINLAND
TRANSMISSION PLAN



NICOLA - MERIDIAN
#2 500 kV TRANSMISSION LINE

FIG. 6.5

INTERIOR-LOWER MAINLAND TRANSMISSION PLAN



500 kV SWITCHING STATION
NEAR RUBY CREEK

FIG. 6.6

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LM + VI Load Limit Change
Sensitivity to Local & Remote Generation Changes

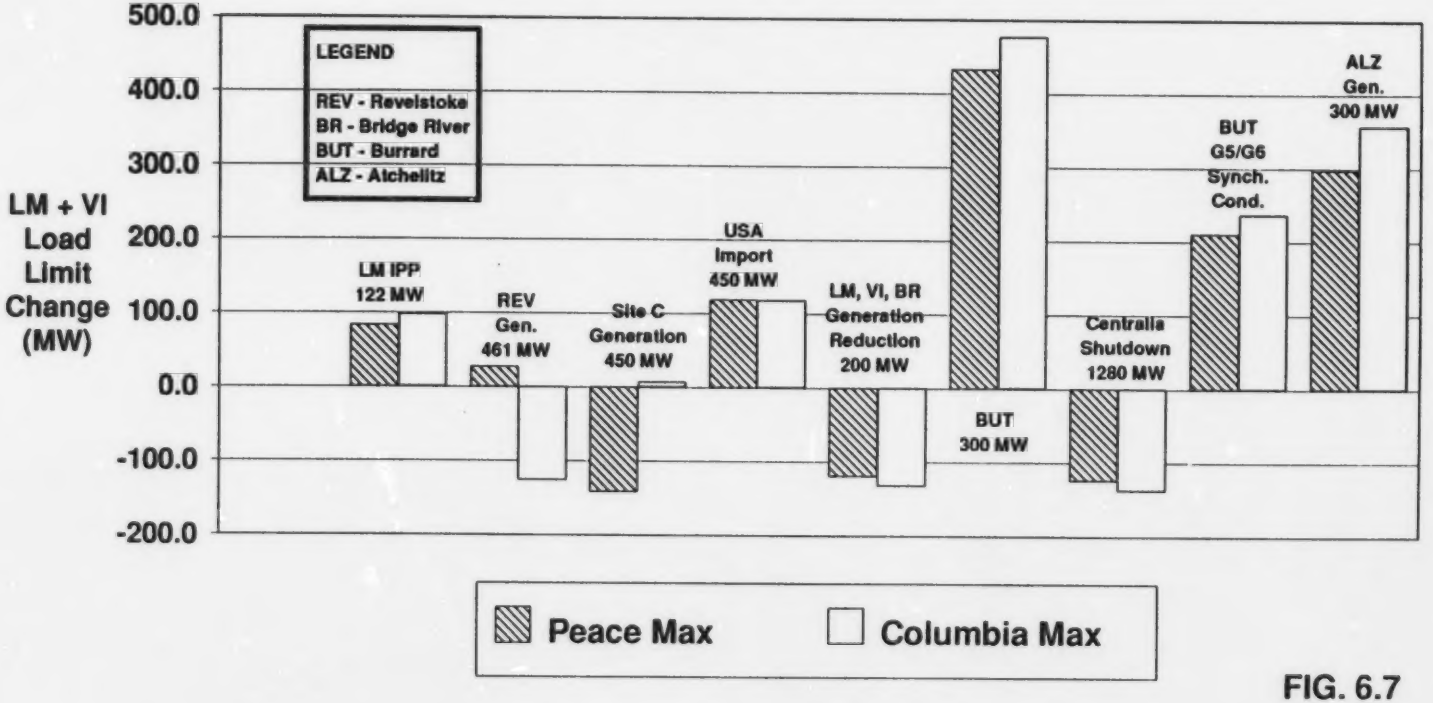
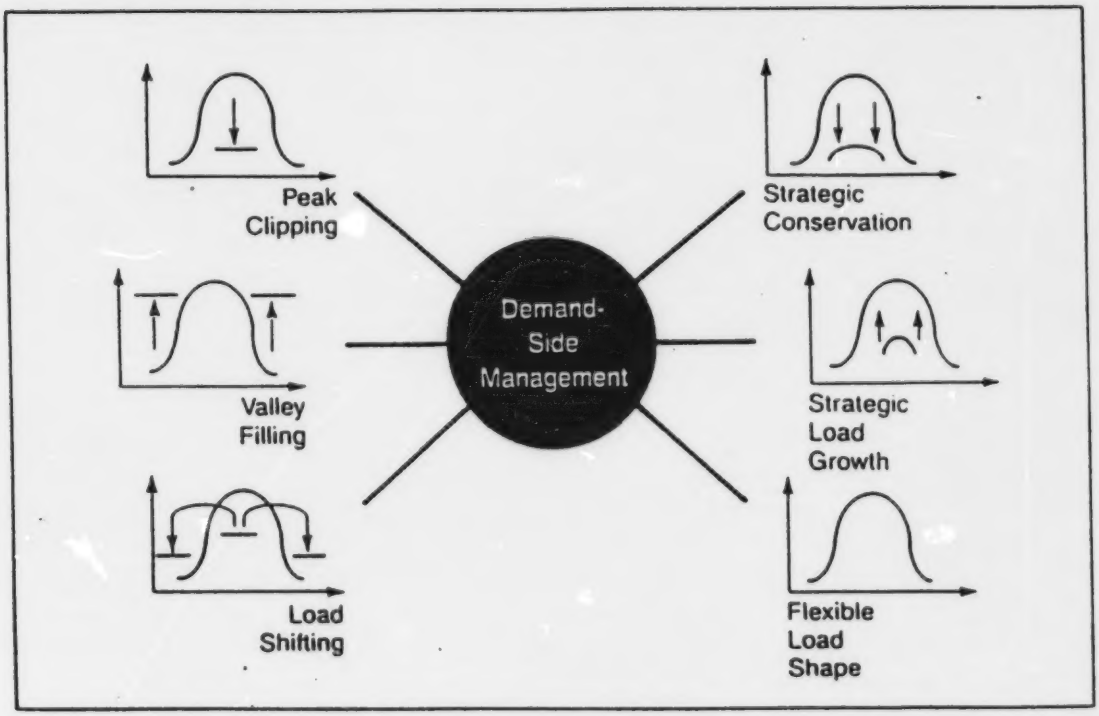


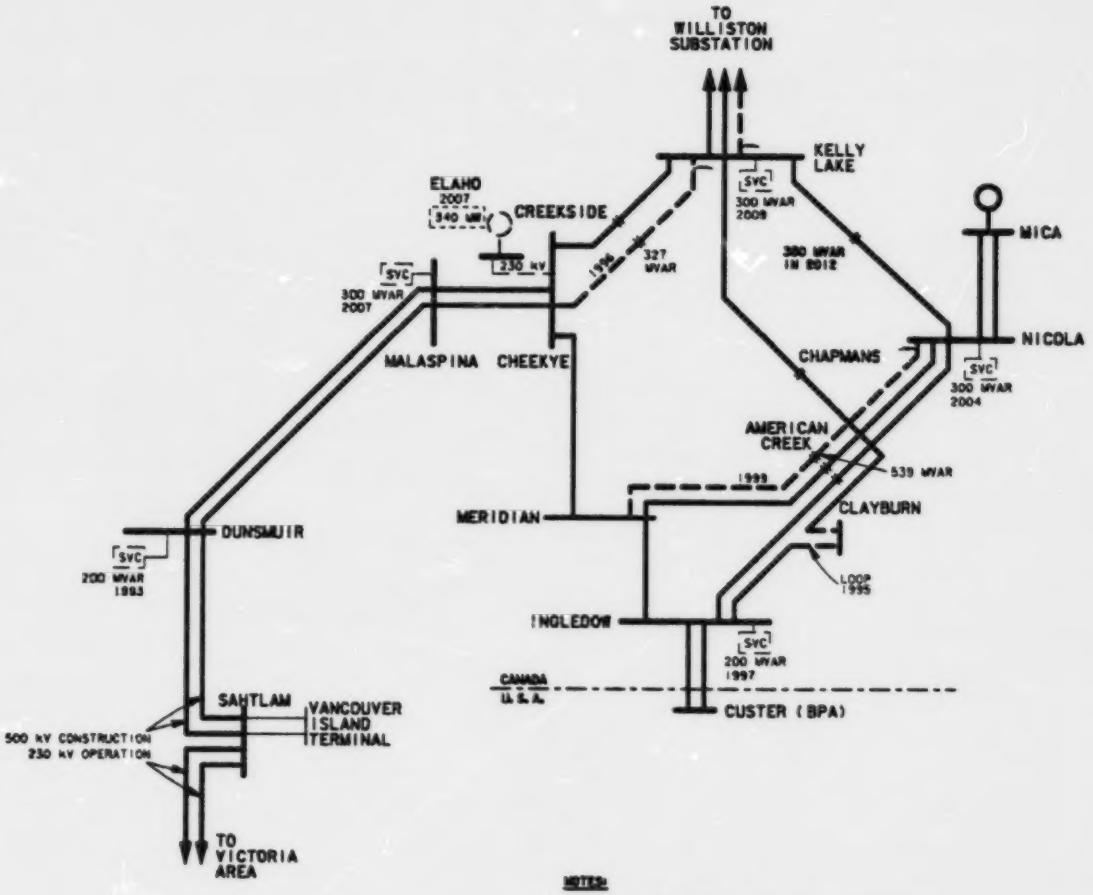
FIG. 6.7

DEMAND-SIDE MANAGEMENT



Source: Electric Power Research Institute

FIG. 6.8



NOTES:

1. VOLTAGE STABILITY STUDIES DO NOT ACCOUNT FOR GENERATION ADDITIONS SCHEDULED AFTER 2008.
2. ASSUMES ALL STATIC VAR COMPENSATORS (SVC) CONNECTED TO 230 kV BUS.
3. YEARS CORRESPOND TO 1st YEAR OF FISCAL YEARS (1 APR TO 31 MAR OF FOLLOWING YEAR).
4. SVC RATINGS ARE CAPACITIVE ONLY.
5. VANCOUVER ISLAND NET LOAD GROWTH AFTER 2002 ASSUMED TO BE TO BE ZERO (MET BY LOCAL GENERATION OR BY LOAD MANAGEMENT ON V.I.).
6. INCREASE FROM 50X TO 60X SERIES COMPENSATION AT CHAPMANS, CREEKSIDE, AND AMERICAN CREEK IN 2011.
7. 50X SERIES COMPENSATION ON NICOLA - KELLY LAKE (5L87) IN 2012.

ASSUMED RESOURCE PLAN
(AS PER TABLE 4.1)

RESOURCES	PROBABLE	RESOURCES	PROBABLE
KEEMLEYSIDE	1999	MURPHY CREEK	2009
BANETA EXP.	2002	ELAHO	2007
SEVEN MILE 4	2003	BORDER	2013
BRILLIANT EXP.	2005		
PEACE SITE C	2003		
DUNCAN	2006		
LOWER CANYON	2006		

NOTE: FOR THIS PLAN IT HAS BEEN ASSUMED THAT DOWNSTREAM BENEFITS WILL BE RETURNED 50X AT INGLEDOW AND 50X AT SELKIRK.

TOTAL TO B.C.H.: 1998/99 - 100 MW
1999/00 - 600 MW
2003/04 - 1100 MW

KEY

- EXISTING 500 kV EHV TRANSMISSION
- PLANNED 500 kV EHV TRANSMISSION
- EXISTING 230 kV HV TRANSMISSION
- PLANNED 230 kV HV TRANSMISSION

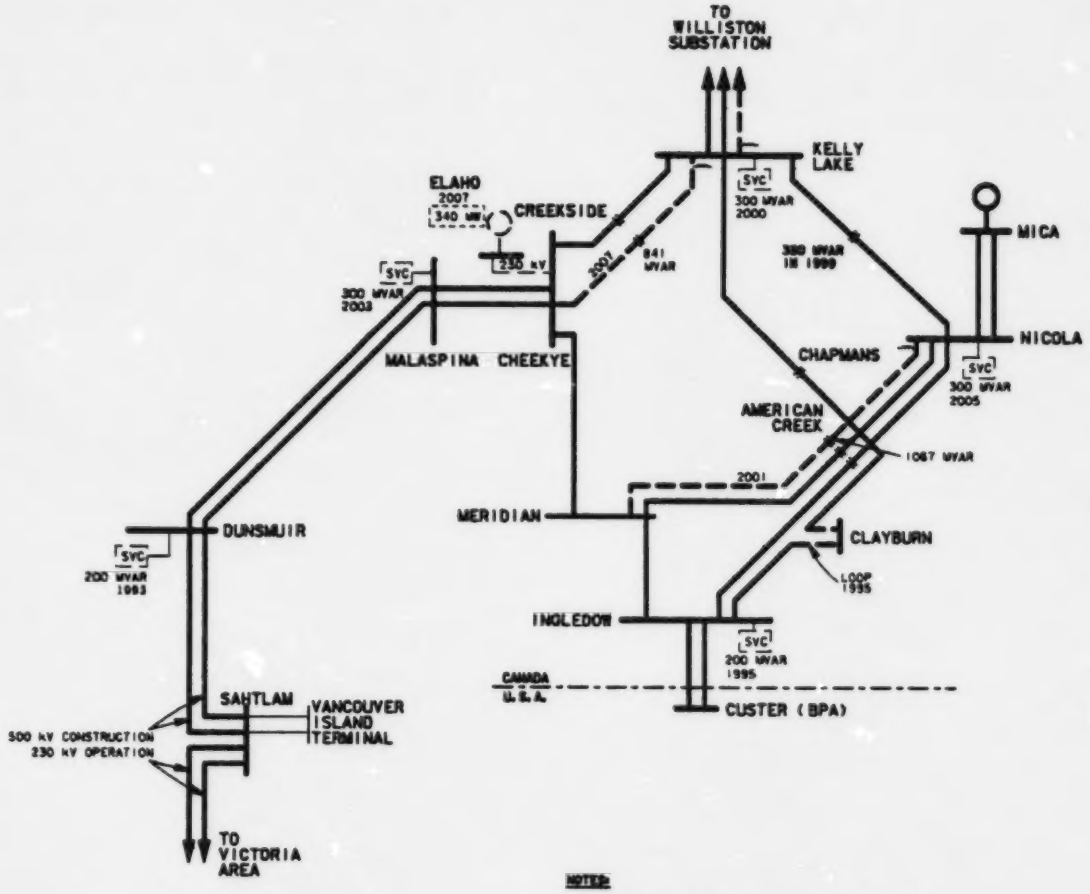
FIG. 6.9

BC hydro System Planning Division

INTERIOR TO LOWER MAINLAND
500 KV TRANSMISSION
SEQUENCE I
TRANSMISSION BEGINNING IN 1996 WITH 5L46

DWG No. CJ5.DGN SHT. 1

C.J. - 14 FEB 91



NOTES:

1. VOLTAGE STABILITY STUDIES DO NOT ACCOUNT FOR GENERATION ADDITIONS SCHEDULED AFTER 2008.
2. ASSUMES ALL STATIC VAR COMPENSATORS (SVC) CONNECTED TO 230 kV BUS.
3. YEARS CORRESPOND TO 1st YEAR OF FISCAL YEARS (1 APR TO 31 MAR OF FOLLOWING YEAR).
4. SVC RATINGS ARE CAPACITIVE ONLY.
5. VANCOUVER ISLAND NET LOAD GROWTH AFTER 2002 ASSUMED TO BE TO BE ZERO (MET BY LOCAL GENERATION OR BY LOAD MANAGEMENT ON V. I.).
6. INCREASE FROM 50% TO 60% SERIES COMPENSATION AT CHAPMANS, CREEKSIDE, AND AMERICAN CREEK IN 1997.
7. 60% SERIES COMPENSATION ON NICOLA - KELLY LAKE (SL97) IN 1998.

ASSUMED RESOURCE PLAN
(AS PER TABLE 4.1)

RESOURCE	PROBABLE	RESOURCE	PROBABLE
KEENLEYSIDE	1998	MURPHY CREEK	2009
WANETA EXP.	2002	ELAHO	2007
SEVEN MILE 4	2003	BORDER	2013
BRILLIANT EXP.	2005		
PEACE SITE C	2003		
DUNCAN	2005		
LOWER CANYON	2005		

NOTE: FOR THIS PLAN IT HAS BEEN ASSUMED THAT DOWNSTREAM BENEFITS WILL BE RETURNED 50% AT INGLEDOW AND 50% AT SELKIRK.

TOTAL TO B.C.H.: 1998/99 - 100 MW
1999/00 - 600 MW
2003/04 - 1100 MW

KEY

- EXISTING 500 kV DBY TRANSMISSION
- PLANNED 500 kV DBY TRANSMISSION
- EXISTING 230 kV MV TRANSMISSION
- PLANNED 230 kV MV TRANSMISSION

FIG. 6.10

BCHydro System Planning Division

INTERIOR TO LOWER MAINLAND
500 KV TRANSMISSION
SEQUENCE 2
DEFERRED TRANSMISSION ALTERNATIVE

DWG No. CJ5.DGN SHT. 2

C.J. - 14 FEB 91

INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENT
SEQUENCE 1
STAGING AND SINGLE - CONTINGENCY
DYNAMIC VAR RESERVE

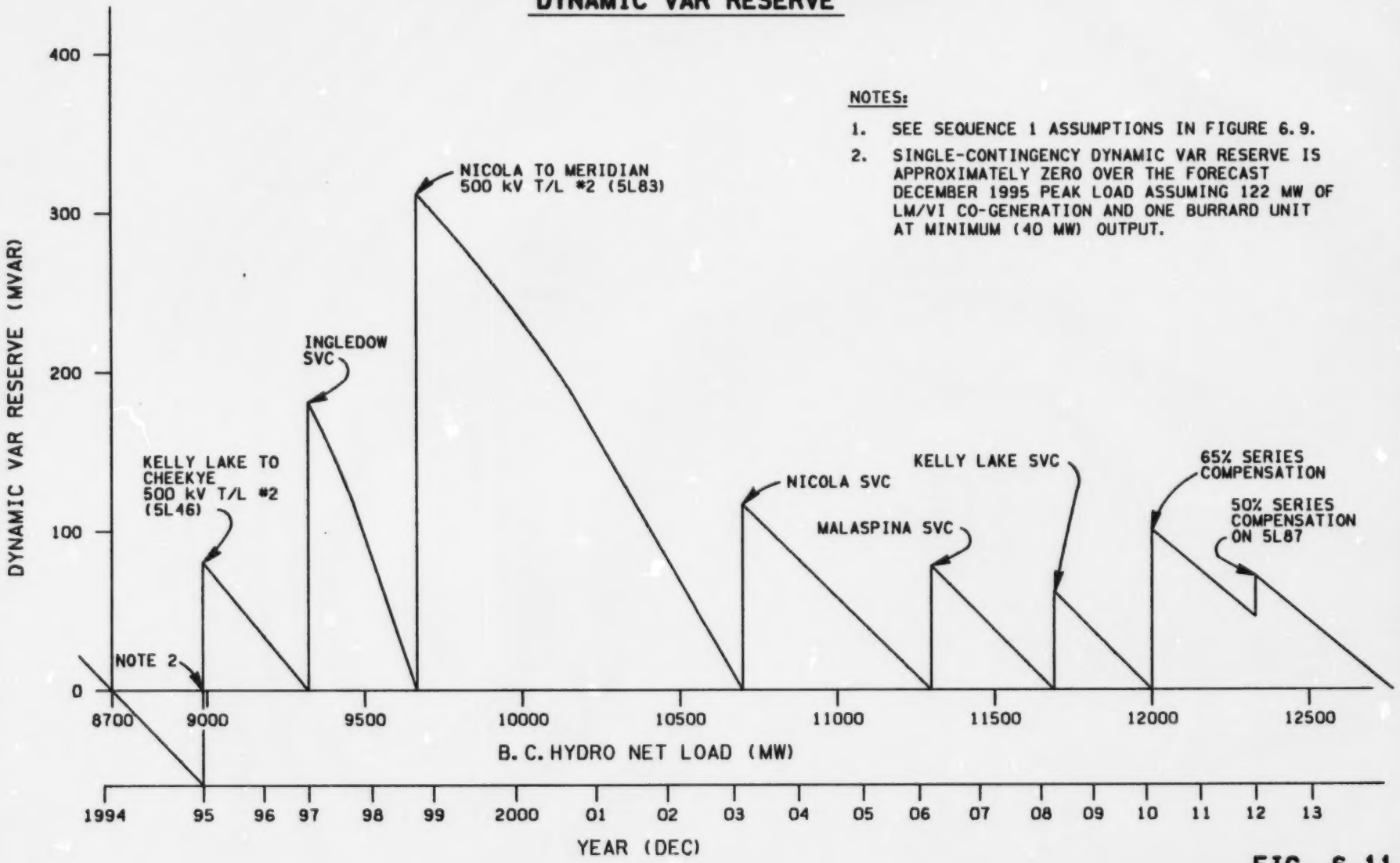


FIG. 6.11

INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENT
SEQUENCE 2
STAGING AND SINGLE - CONTINGENCY
DYNAMIC VAR RESERVE

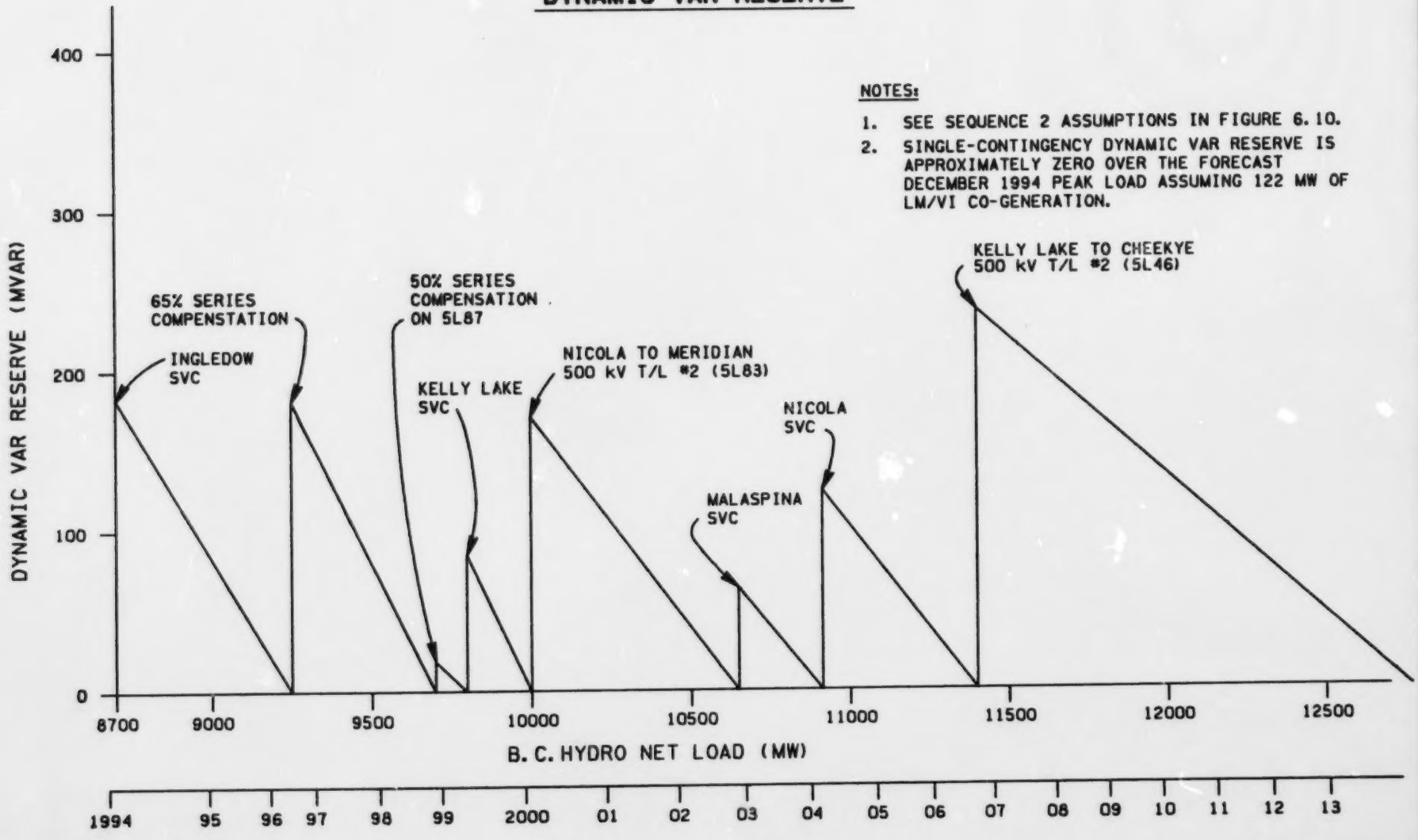
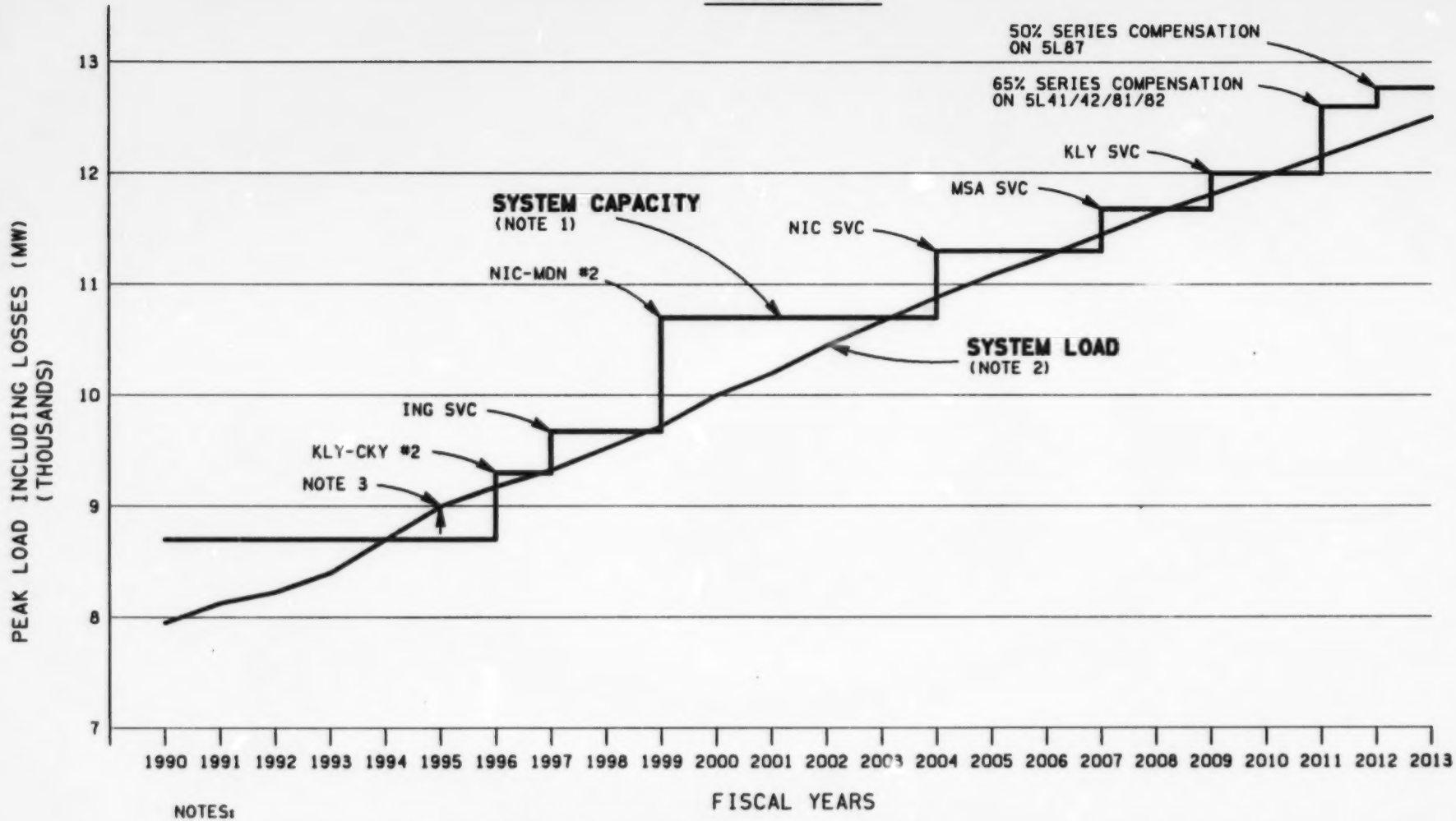


FIG. 6.12

B.C. HYDRO NET LOAD VS FIRM TRANSMISSION CAPABILITY FOR SEQUENCE 1

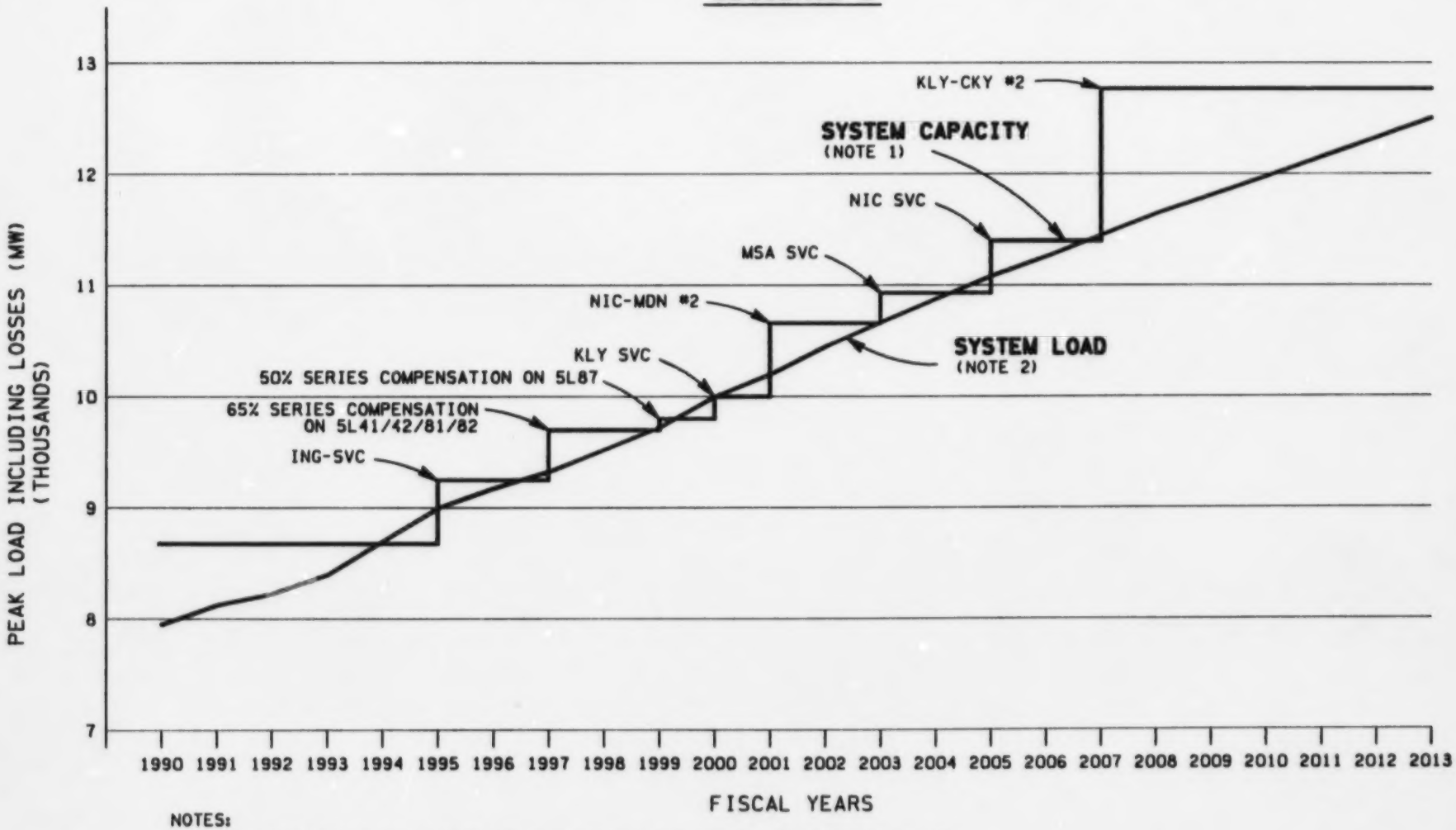


NOTES:

1. CAPABILITY STEPS ARE DERIVED FROM THE DYNAMIC VAR RESERVE (MVAR) INCREASES SHOWN IN FIGURE 6-11.
2. B.C. HYDRO INTEGRATED SYSTEM NET LOAD IS THE FORECAST (SEPT '90) PROBABLE PEAK CONNECTED LOAD PLUS LOSSES AND INCLUDES ALLOWANCE FOR DSM, AND E+ PROGRAMS, AND ZERO VANCOUVER ISLAND (NET) LOAD GROWTH AFTER 2002.
3. ONE TIME USE OF A SINGLE BURRARD UNIT AT MINIMUM OUTPUT (40 MW) WILL PROVIDE THE REQUIRED FIRM TRANSMISSION CAPABILITY OVER 1995/96 PEAK LOAD.

FIG. 6.13

B. C. HYDRO NET LOAD VS FIRM TRANSMISSION CAPABILITY FOR SEQUENCE 2



NOTES:

1. CAPABILITY STEPS ARE DERIVED FROM THE DYNAMIC VAR RESERVE (MVAR) INCREASES SHOWN IN FIGURE 6-12.
2. B. C. HYDRO INTEGRATED SYSTEM NET LOAD IS THE FORECAST (SEPT '90) PROBABLE PEAK CONNECTED LOAD PLUS LOSSES AND INCLUDES ALLOWANCE FOR DSM, AND E+ PROGRAMS, AND ZERO VANCOUVER ISLAND (NET) LOAD GROWTH AFTER 2002.

FIG. 6.14

TOTAL SYSTEM LINE LOSS REDUCTION

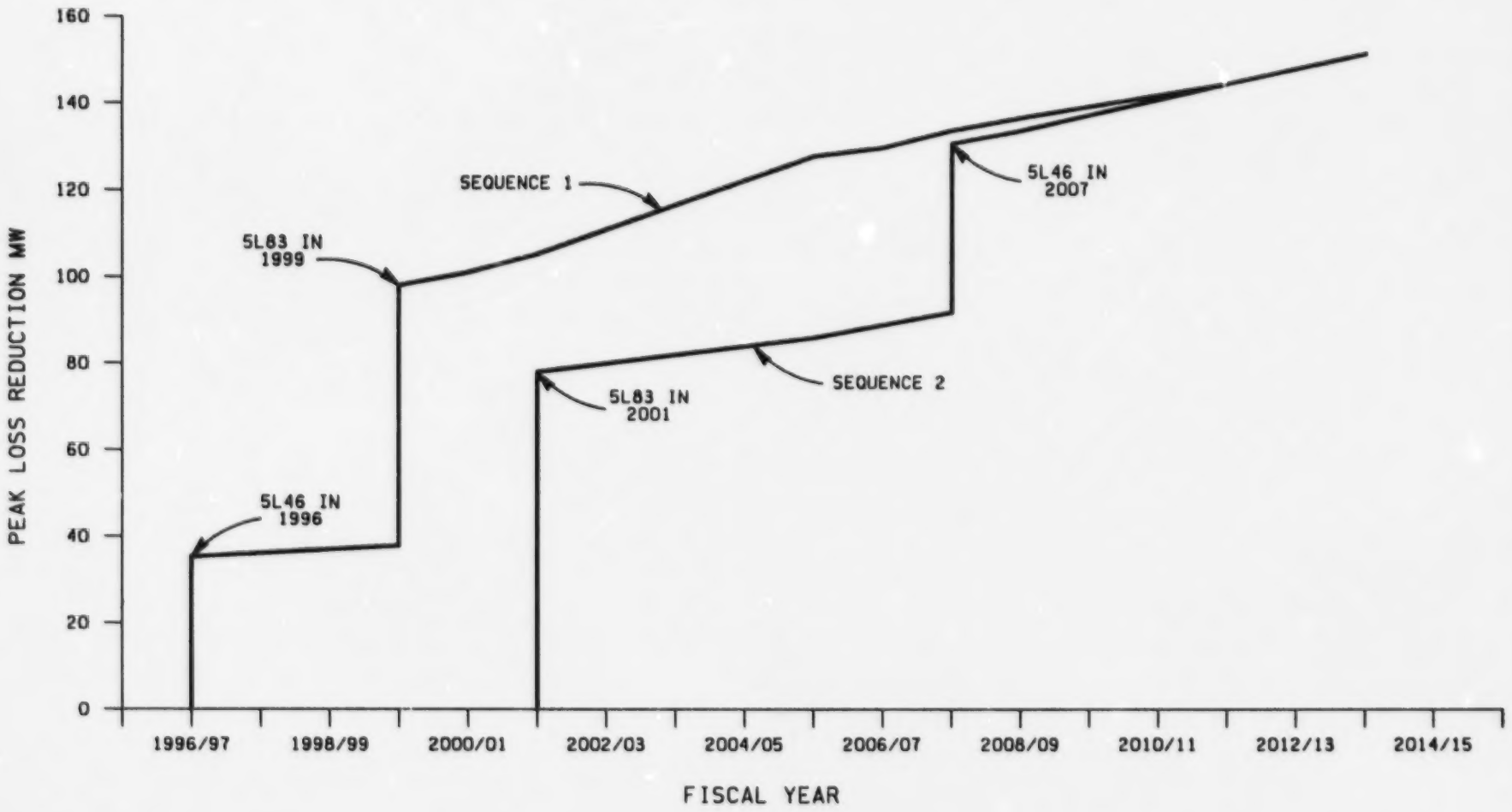


FIG. 6.15

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO DISCOUNT RATE

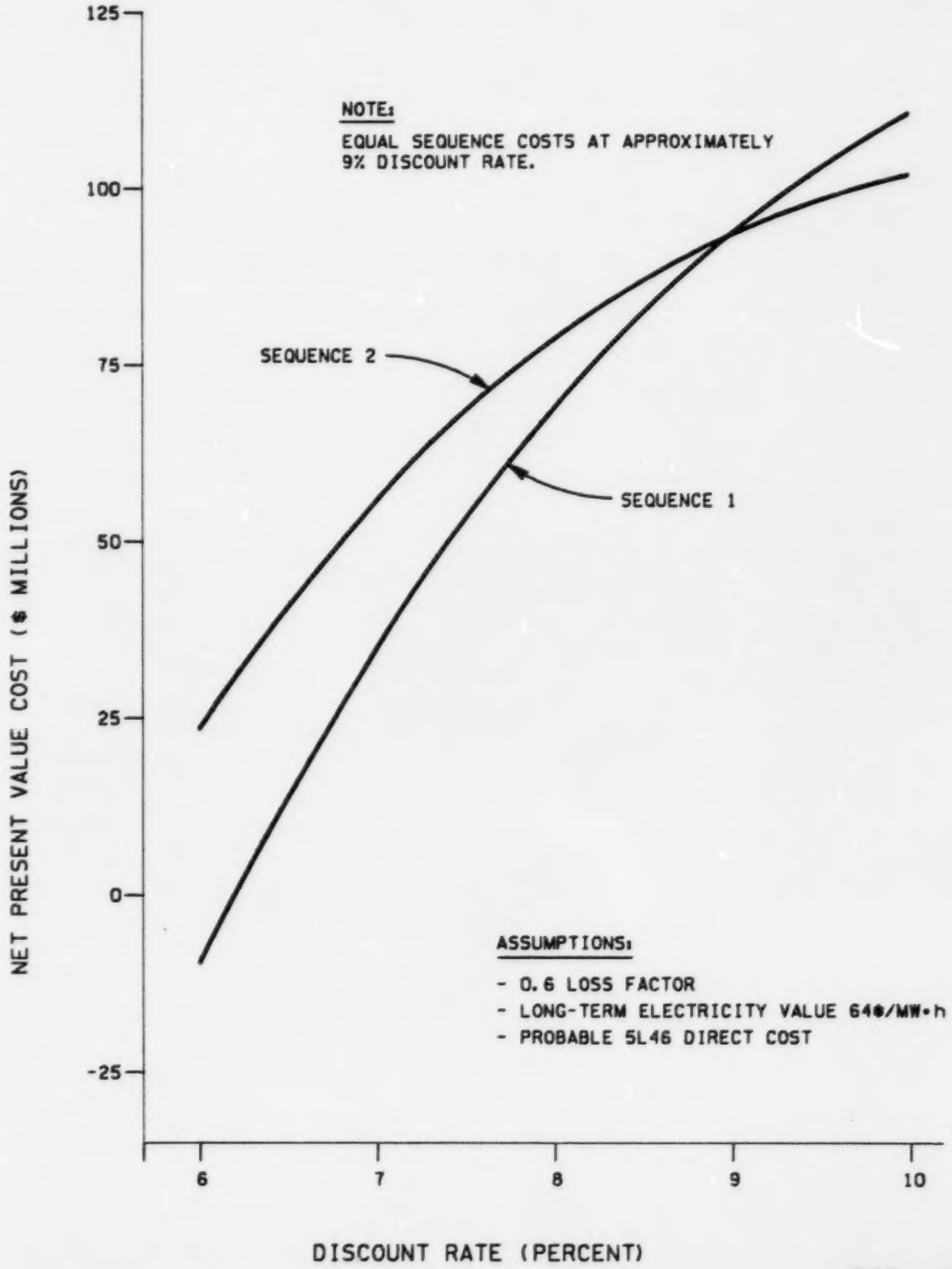


FIG. 6.16

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO LONG-TERM ELECTRICITY VALUE

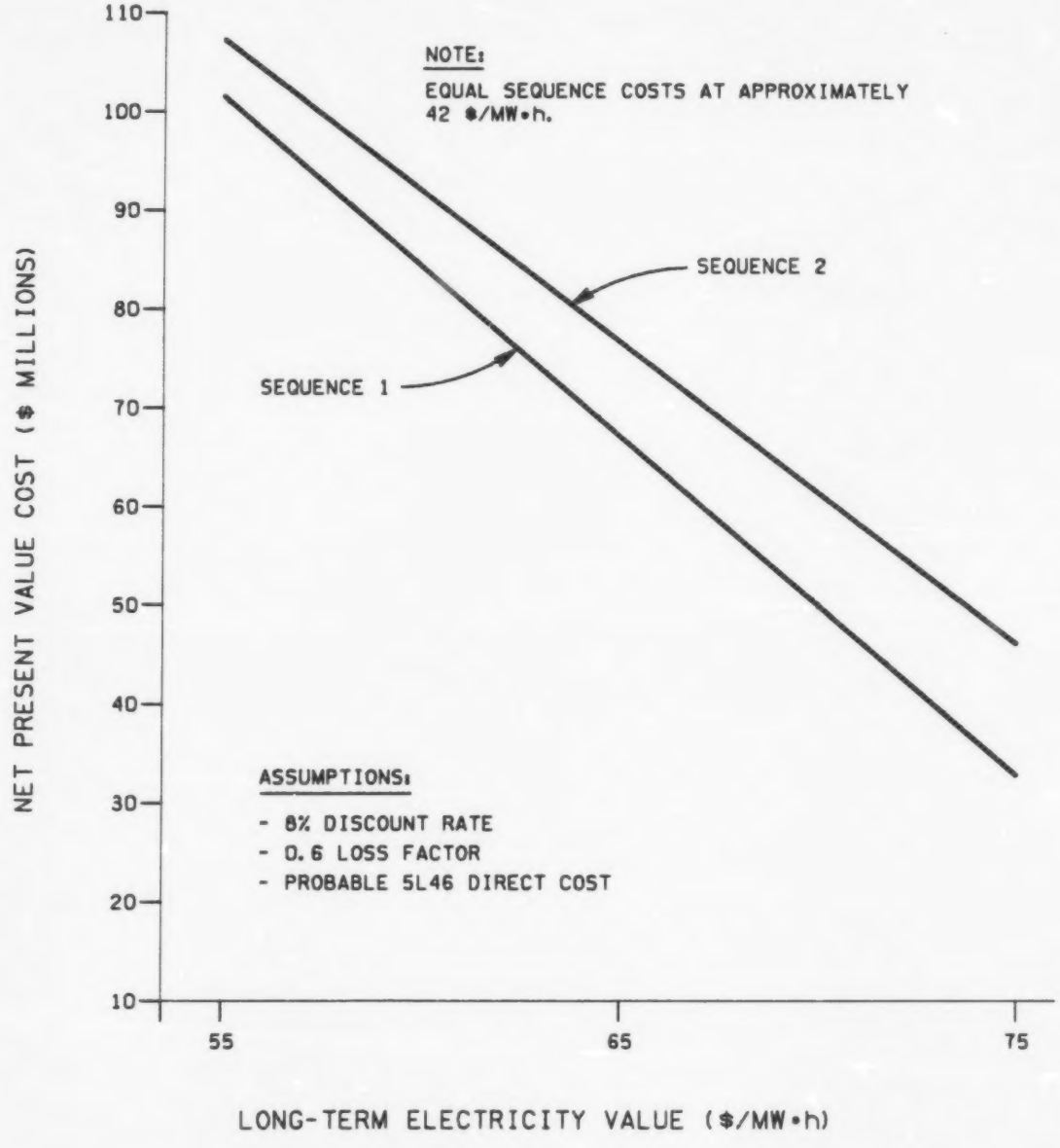


FIG. 6.17

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO LOSS FACTOR

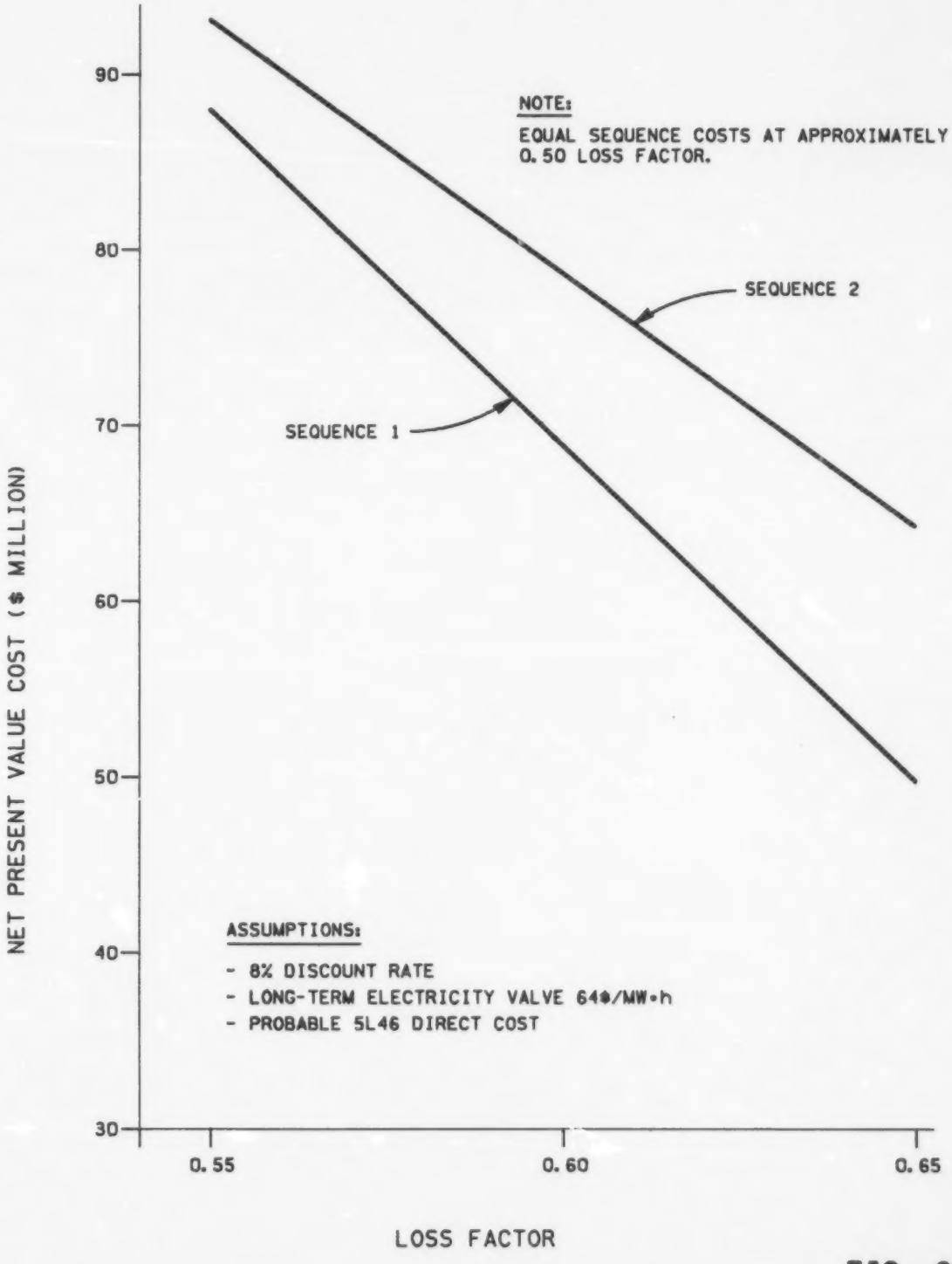


FIG. 6.18

KELLY LAKE - CHEEKYE 500 KV NO. 2 (5L46)

ECONOMIC ANALYSIS

SENSITIVITY TO 5L46 DIRECT COST

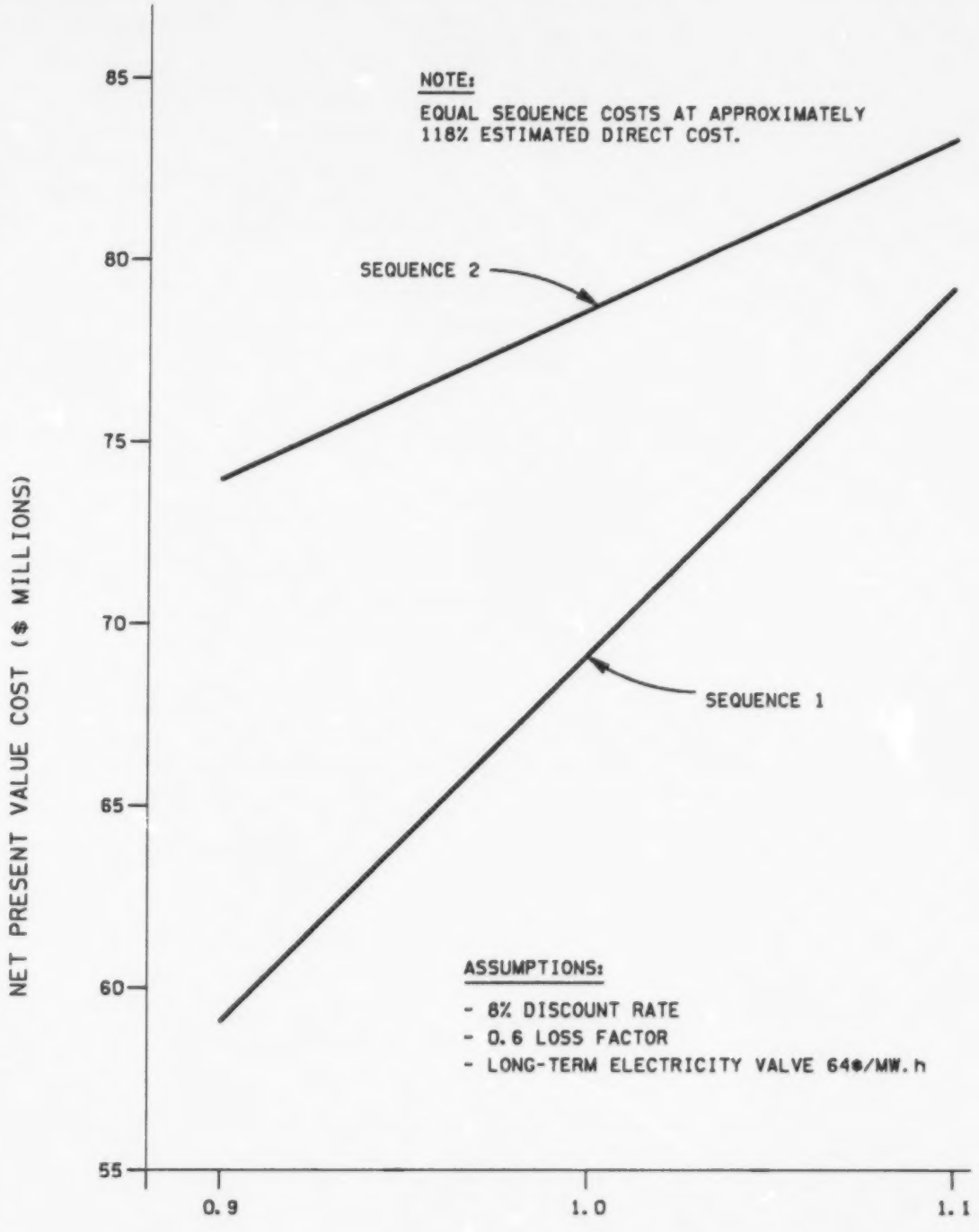


FIG. 6.19

PROPOSED TRANSMISSION ROUTE AND ALTERNATIVES
KELLY LAKE - CHEEKYE 500 kV
TRANSMISSION LINE (5L46)

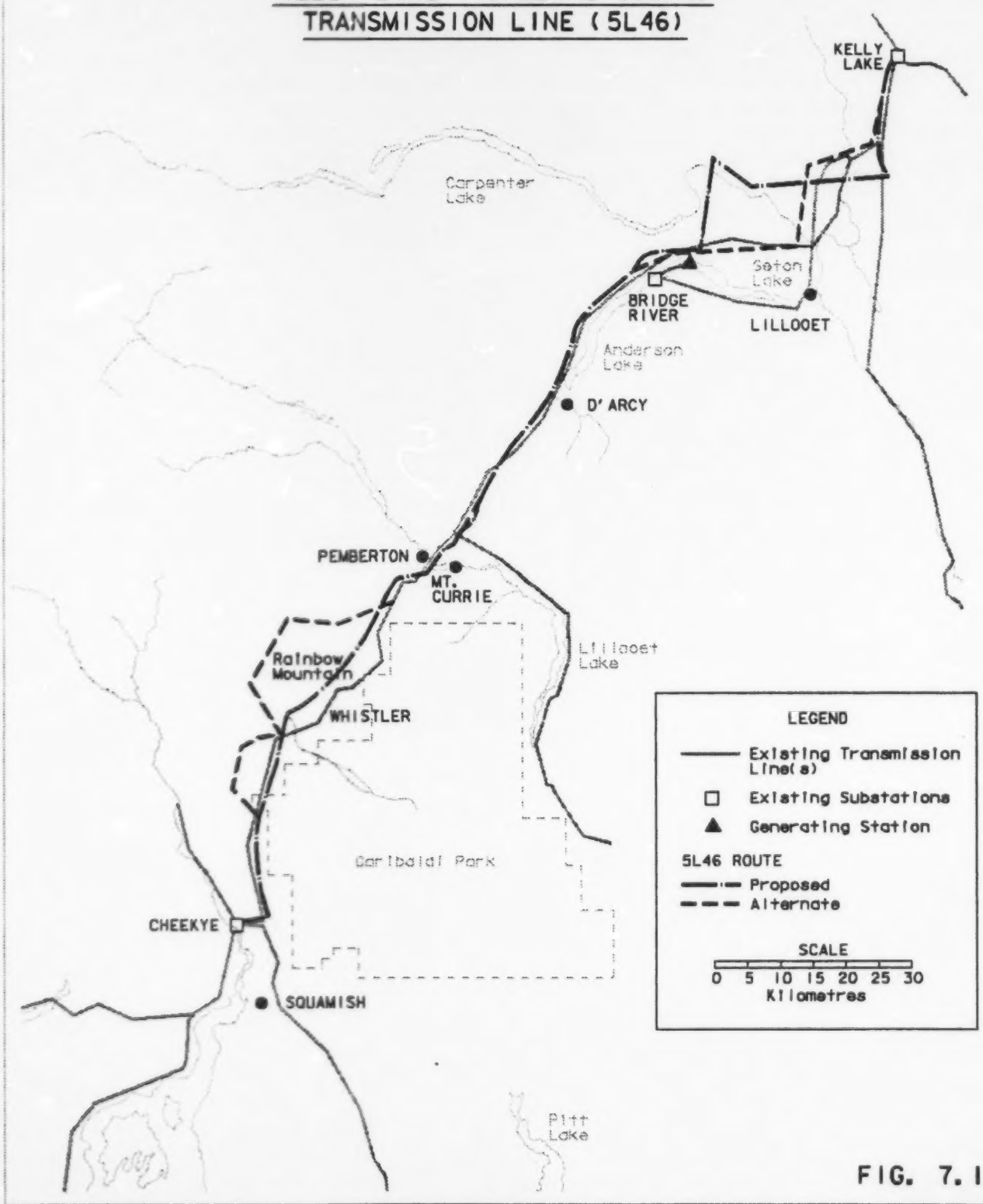
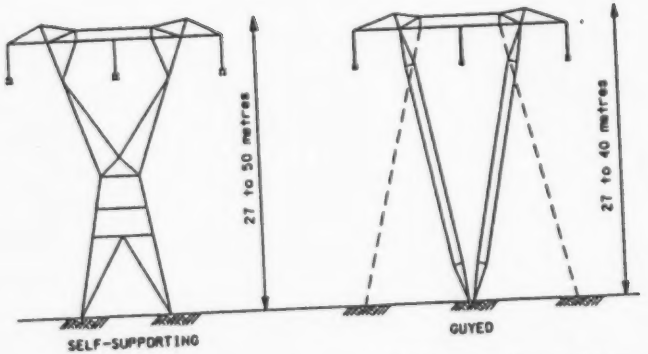
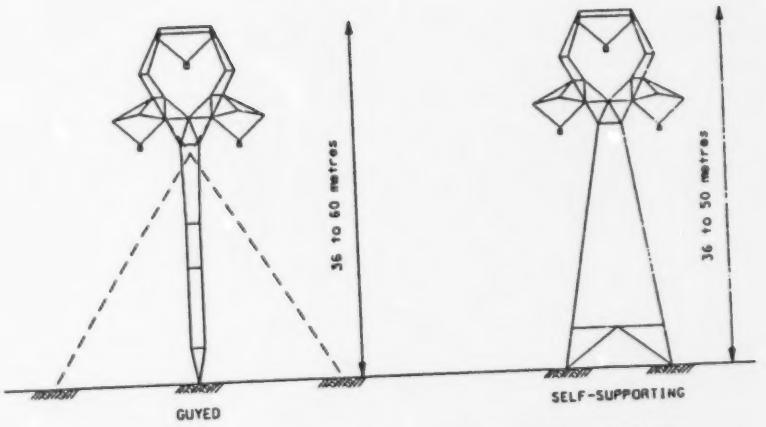


FIG. 7.1

KELLY LAKE - CHEEKYE
500 kV TRANSMISSION LINE PROJECT
STRUCTURE TYPES



Outline of conventional (flat) configuration



Outline of Delta configuration

FIG. 7.2

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Table 3.1
B.C. Hydro Total Generation Requirement
During Winter Peak Load Hour

Based on Fall 1990 Forecast

MW

Winter	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11
Generation for B.C. Hydro Load	7883	8146	8342	8614	8967	9326															
(Last Year Forecast)	7870	8160	8420	8680	8900	9170	9410	9610	9850	10090	10380	10630	10890	11160	11420	11680	11920	12170	12410	12620	
Extrapolated Load *	**7883**	**8146**	**8342**	**8614**	**8967**	**9326**	**9566**	**9766**	**10006**	**10246**	**10536**	**10786**	**11046**	**11316**	**11576**	**11836**	**12076**	**12326**	**12566**	**12776**	**12990**
DSM	-55	-145	-233	-321	-395	-457	-504	-554	-602	-643	-672	-691	-704	-714	-725	-739	-754	-770	-785	-799	-813
Subtracting DSM	7828	8001	8109	8293	8572	8869	9062	9212	9404	9603	9864	10095	10342	10602	10851	11097	11322	11556	11781	11977	12176
E+ (Electric Plus)	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
Including DSM & E+ (note)	**7943**	**8116**	**8224**	**8408**	**8687**	**8984**	**9177**	**9327**	**9519**	**9718**	**9979**	**10210**	**10457**	**10717**	**10966**	**11212**	**11437**	**11671**	**11896**	**12092**	**12291**
Generation for Export to WKPL **	150	171	47	50	105	118	133	146	166	165	179	189	202	213	228	239	253	266	281	297	312
SCL Firm Contract	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124	124
Total Generation needed Including WKPL and SCL	**8217**	**8411**	**8395**	**8582**	**8916**	**9226**	**9434**	**9597**	**9809**	**10007**	**10282**	**10523**	**10783**	**11054**	**11318**	**11575**	**11814**	**12061**	**12301**	**12513**	**12727**

Note: This is the "probable" peak load for the BC Hydro Integrated System. The average annual growth rate is 2.2 %

** After 1995 Annual Growth same as Last Year's Forecast*

*** Diversity Factor 0.95 and Loss Factor 1.07 for WKPL loads*

Table 3.2
V.I. Total Generation Requirement
During Winter Peak Load Hour

Based on Fall 1990 Forecast
(Assumes Natural Gas to V.I. in 1991)

MW

December	90	91	92	93	94	95	96	97	98	99	00	01	02	03	04	05	06	07	08	09	10
Generation for V.I. Load	1880	1930	1980	2070	2160	2220															
(Last Year Forecast)	1900	2000	2080	2150	2190	2230	2250	2270	2270	2240	2280	2320	2370	2420	2460	2500	2550	2590	2620	2650	
Extrapolated Load *	**1880**	**1930**	**1980**	**2070**	**2160**	**2220**	**2240**	**2260**	**2260**	**2230**	**2270**	**2310**	**2360**	**2410**	**2450**	**2490**	**2540**	**2580**	**2610**	**2640**	**2670**
Percentage Growth		2.66%	2.59%	4.55%	4.35%	2.78%	0.90%	0.89%	0.00%	-1.33%	1.79%	1.76%	2.16%	2.12%	1.66%	1.63%	2.01%	1.57%	1.16%	1.15%	1.15%

* After 1995 Annual Growth same as Last Year's Forecast

Note: This is the "probable" peak load for the Vancouver Island System

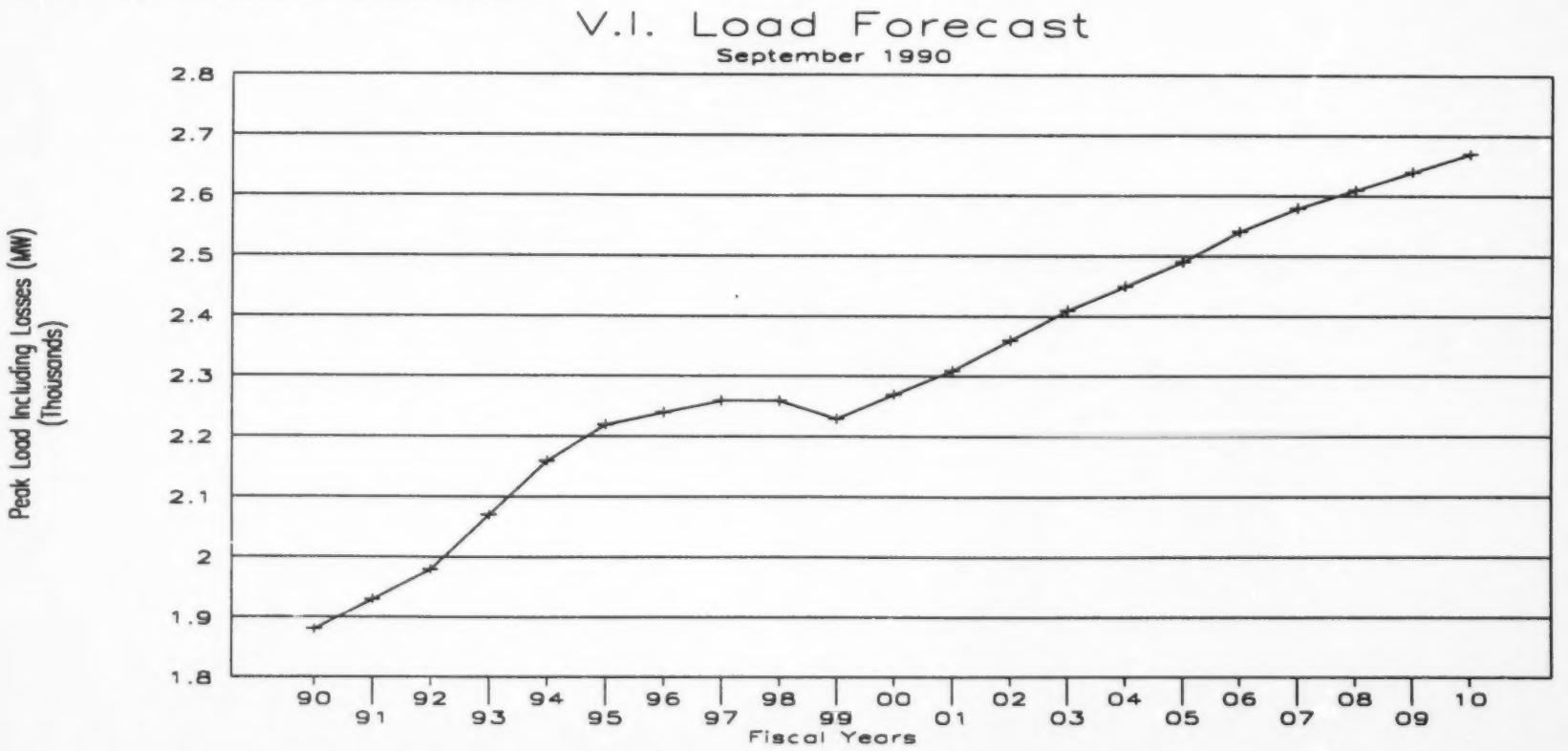


TABLE 4.1

RESOURCE DEVELOPMENT SUMMARY
SCHEDULED & POSSIBLE NEW RESOURCES

YEAR	RESOURCE ADDITION	REGIONAL LOCATION	RATED CAPACITY MW	CUMLATIVE CAPACITY ADDITIONS BY REGION				YEARLY CAPACITY ADDITIONS	
				LM & VI MW	PEACE MW	COLUMBIA MW	OVERALL TOTAL MW	YEAR	ADDED MW
1993	McMahon (Taylor)	Peace	105	0	105	0	105	1991/92	None
1993	NW Energy (Williams Lake)	Peace	55	0	160	0	160		
1993	Mamquam (Squamish)	LM	50	50	160	0	210	1993	210
1994	LM & VI Self Generation	LM & VI	90	140	160	0	300		
1994	Peace Self Generation	Peace	115	140	275	0	415		
1994	Columbia Self Generation	Columbia	40	140	275	40	455	1994	245
1995	Kemano Completion Project	Peace	520	140	795	40	975	1995	520
1996	LM & VI Self Generation	LM & VI	60	200	795	40	1035		
1996	Peace Self Generation	Peace	80	200	875	40	1115	1996	140
1998	Downstream Benefits (LM)))100	LM	50	250	875	40	1165	1997	None
1998	Downstream Benefits (SI))	Columbia	50	250	875	90	1215	1998	215
1998	Peace Self-Generation	Peace	100	250	975	90	1315		
1998	Columbia Self-Generation	Columbia	15	250	975	105	1330		
1999	Keenleyside	Columbia	240	250	975	345	1570		
1999	Downstream Benefits (LM)))500	LM	250	500	975	345	1820		
1999	Downstream Benefits (SI))	Columbia	250	500	975	595	2070	1999	740
2002	Waneta Expansion	Columbia	380	500	975	975	2450	2000/01 2002	None 380
2003	Site C	Peace	900	500	1875	975	3350		
2003	Seven Mile #4	Columbia	200	500	1875	1175	3550		
2003	Downstream Benefits (LM)))500	LM	250	750	1875	1175	3800		
2003	Downstream Benefits (SI))	Columbia	250	750	1875	1425	4050	2003	1600
2005	Brilliant Expansion	Columbia	150	750	1875	1575	4200	2004 2005	None 150
2006	Duncan	Columbia	25	750	1875	1600	4225		
2006	Lower Canyon	Peace	360	750	2235	1600	4585	2006	385
2007	Elaho	LM	340	1090	2235	1600	4925	2007	340
2009	Murphy Creek	Columbia	275	1090	2235	1875	5200	2008 2009	None 275
2013	Border	Columbia	275	1090	2235	2150	5475	2010/12 2013	None 275

TABLE 5.1

RECORD OF MAJOR OUTAGES OF THE INTERIOR TO LOWER MAINLAND 500 KV LINES

1972-1990 Record of Outages of the Kelly Lake to Cheekye Line (5L42)

YEAR	DATE	DURATION	CAUSE
1990	11 November	13 days	Flooding of the Green River near Tisdall; one tower washed away, two others damaged
1987	15 August	9 days	Rolling log; tower knocked down
1980	26 December	1 week (approx)	Flooding of Rutherford Creek; tower footings washed away
1973 to 1979		>1 day	Several outages due to mud slides and snow slides
1972	20 January	8 days	Snow storm and extreme icing; one tower down (concurrent outage of 5L41, Kelly Lake to Ingledow, with 25 towers down, which isolated Peace generation (800 MW) & took 5 weeks to restore; the intertie with BPA provided required back-up supply for a total of approximately 30,000 MW.h)

1980-1990 Record of Outages of Other Interior to Lower Mainland Lines

Kelly Lake to Ingledow	(5L41):	Nil
Nicola to Ingledow	(5L81):	Nil
Nicola to Meridian	(5L82):	February 1990, 2-day outage due to snow storm

TABLE 5.2

EXHIBIT 1

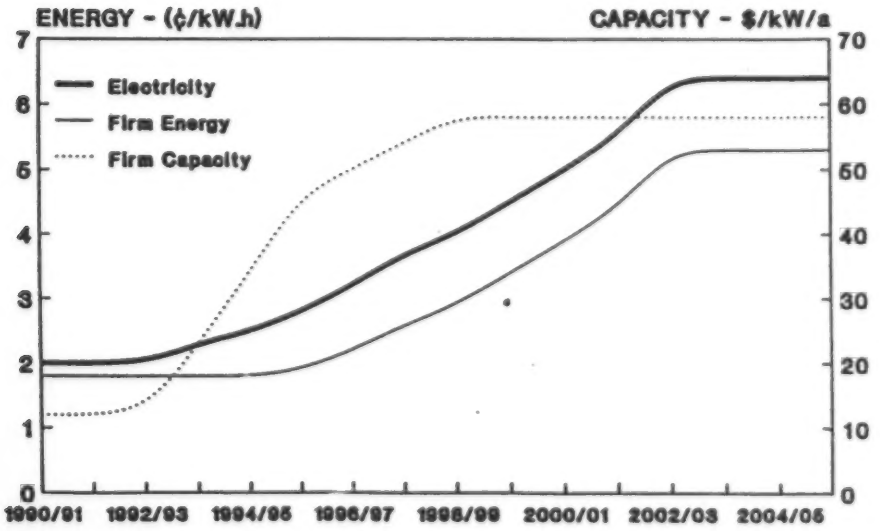
COST OF NEW ELECTRICITY SUPPLY DELIVERED TO THE LOWER MAINLAND
October 1990 Dollars

	Electricity[1] (¢/kW·h)	Firm Capacity $/kW/a	Energy (¢/kW·h)
1990/91	2.0	12	1.8
1991/92	2.0	12	1.8
1992/93	2.0	12	1.8
1993/94	2.3	23	1.8
1994/95	2.5	34	1.8
1995/96	2.8	46	1.9
1996/97	3.2	50	2.2
1997/98	3.7	54	2.6
1998/99	4.0	58	2.9
1999/00	4.5	58	3.4
2000/01	5.0	58	3.9
2001/02	5.5	58	4.4
2002/03 on	6.4	58	5.3

[1] The capacity factor of the B.C. Hydro system is about 65% or 58% after allowing for a 12% reserve margin. Therefore, on average each kW of installed capacity would produce 5080 kW.h/year (0.58 kW x 8760 hours/year). Based on these values a capacity cost of $1/kW/year is equivalent to 1/5080 = 0.0197¢/kW.h.

EXHIBIT 2

COST OF NEW ELECTRICITY SUPPLY
Delivered To The Lower Mainland



Ref: From The Cost of New Electricity Supply in British Columbia, Resource Planning, Corporate and Environmental Affairs, December 1990.

TABLE 6.1

SYSTEM REINFORCEMENT ALTERNATIVES CONSIDERED

Class A Alternatives

* Kelly Lake to Cheekye second 500 kV transmission line (Fig. 6.4)
* Lower Mainland and Vancouver Island shunt capacitors for system pre-disturbance voltage support
* Static var compensators (SVCs) at 500/230 kV substations in the Lower Mainland and Vancouver Island regions (e.g., at Ingledow, Kelly Lake, Nicola, Malaspina or Area Transmission)
* Nicola to Meridian second 500 kV transmission line (Fig. 6.5)
* Permanent increase from 50% to 65% in series compensation of the Interior to Lower Mainland 500 kV transmission lines
* 500 kV switching station in the Ruby Creek/Harrison Lake area, for sectionalizing some of the existing 500 kV lines (e.g., 5L41, 5L81 and 5L82) (Fig. 6.6)
* New series compensation of 500 kV circuit from Kelly Lake to Nicola (5L87) (to remove thermal limits on 5L81 and 5L82)

Class B Alternatives

* Joint var control (JVC) and line drop compensation (LDC) at major generating plants and synchronous condensers such as Bridge River, Burrard Thermal and VIT
* Operating circuit 2L2 (Bridge River to Cheekye) at 360 kV instead of 230 kV and adding series compensation to that circuit

Class C Alternatives

* Temporary boost from 50% to 65% series compensation of Interior to Lower Mainland lines
* Kelly Lake to Meridian 500 kV transmission line
* Nicola to Ingledow second 500 kV transmission line
* Operation of Burrard Thermal units #5 & #6 as synchronous condensers or at minimum output
* Area Transmission upgrades
* Series compensation of BPA's 500 kV lines (Custer-Monroe)
* Add mechanically switched capacitors in Lower Mainland or on Vancouver Island
* Install SVCs at Area Transmission level
* Kelly Lake to Campbell River to Dunsmuir 500 kV transmission line
* Permanent increase from 50% to 80% in series compensation of the Interior to Lower Mainland 500 kV transmission lines
* Institute Lower Mainland coordinated var control
* Interior to Lower Mainland high voltage direct current (HVDC) transmission
* Interior to Lower Mainland 765 kV AC transmission
* Install mid-line SVCs on Interior to Lower Mainland 500 kV transmission lines
* Institute load shedding schemes for single contingency outages

Class D Alternatives

* New line drop compensation at the smaller generating stations in the Lower Mainland and on Vancouver Island
* HVDC runback
* Automatic Generation Control (AGC) runback
* On-load tap change control
* Bulk transmission system overvoltage operation
* Operate lower Vancouver Island transmission (Dunsmuir to Sahtlam to Pike Lake) at 500 kV
* Automatic remedial control of Nelway Phase Shifter
* Rebuild existing lines with High Phase-Order transmission from Kelly Lake to Bridge River to Cheekye
* Shunt reactor tripping

TABLE 6.2

CAPITAL (DIRECT) COSTS OF ALTERNATIVES

The direct capital costs of system reinforcement alternatives are listed below. These costs do not include inflation, corporate overhead or interest during construction.

1990 DOLLARS

	$ Millions
(a) Transmission Lines (includes station terminations and series capacitor costs)	
Kelly Lake to Cheekye #2 500 kV (5L46)	$149.0
Nicola to Meridian #2 500 kV (5L83)	$197.6
Kelly Lake to Cheekye 360 kV High Phase-Order (HPO)	$164.0
(b) Static var Compensators (SVC)	
Ingledow (+200/-100 Mvar) (ING SVC)	$ 19.0
Kelly Lake/Nicola/Malaspina (+300/-150 Mvar) (KLY/NIC/MSA SVC)	$ 26.4 (each)
Area Transmission SVC at Walters (+200/-100 Mvar) and at Kidd #2 (+150/-75 Mvar) (ATM SVC)	$ 34.4 (total)
(c) Increased Series Compensation on 5L41/42/81/82	
To 65% (3000 A continuous overload rating) (65% PERM)	$ 27.7 (total)
To 80% (3000 A continuous overload rating) (80% PERM)	$ 44.8 (total)
Temporary Boost to 65% (65% TEMP)	$ 29.0 (total)
(d) New Series Compensation on 5L71/72/87	
Circuits 5L71/72 to 50% (1900 A continuous overload rating) (50% MCA)	$ 22.5 (total)
Circuit 5L87 to 50% (1900 A continuous overload rating)	$ 11.5*
(e) Others	
Ruby Creek Switching Station (RUBY) (Sectionalize 5L41, 5L81 & 5L82)	$ 39.0
Uprate Bridge River to Cheekye 230 kV Transmission (BR.UPGR) (upgrade to 360 kV operation & series compensation)	$ 25.2
Bridge River, Line Drop Compensation (LDC-BR)	$ 0.3
Mica, Line Drop Compensation (LDC-MCA)	$ 0.2

* This option provides an insignificant increase to the system voltage stability limit but provides significant relief from thermal (ampacity) system constraints.

TABLE 6.3

AGGREGATE NET PRESENT VALUE (NPV)

	At 6% Discount Rate		At 8% Discount Rate (base case)		At 10% Discount Rate	
	$ Million		$ Million		$ Million	
	Sequence 1	Sequence 2	Sequence 1	Sequence 2	Sequence 1	Sequence 2
Present Value, Aggregate Annual Costs*	$412	$356	$349	$287	$305	$238
Transmission Loss Savings	$421	$333	$280	$209	$194	$136
Total Aggregate NPV, net of losses	-$9	$23	$69	$78	$111	$102
Sequence 1 - Sequence 2 Difference	-$32		-$9		+$9	

*Annual costs include charges for interest, depreciation, operating and maintenance and taxes for all projects in the plan

****

TABLE 6.4

LONG TERM PAY BACK OF THE KELLY LAKE TO CHEEKYE PROJECT

	Net Present Value		
	At 6% Discount Rate	At 8% Discount Rate (base case)	At 10% Discount Rate
	$ Million	$ Million	$ Million
Present Value, Project Costs*	$150.7	$135.2	$124.3
Transmission Loss Savings	$171.6	$116.1	$ 81.9
Pay Back (over 45 year lifetime)	114%	86%	66%

*Annual costs include charges for interest, depreciation, operation and maintenance and taxes for the Kelly Lake to Cheekye project only